Decision 2003-100

ATCO Pipelines

2003/2004 General Rate Application
Phase I

December 2, 2003

Alberta Energy and Utilities Board

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ALBERTA ENERGY AND UTILITIES BOARD
Decision 2003-100: ATCO Pipelines
2003/2004 General Rate Application – Phase I
Application No. 1292783

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Contents

List of Tables

ALBERTA ENERGY AND UTILITIES BOARD
Calgary Alberta

ATCO PIPELINES **Decision 2003-100**
2003/2004 GENERAL RATE APPLICATION **Application No. 1292783**
PHASE I **File No. 4100-1**

1 INTRODUCTION

By letter dated February 14, 2002, ATCO Gas and Pipelines Ltd, Pipelines Division (ATCO Pipelines) filed Phase I of its 2003/2004 General Rate Application (GRA) with the Alberta Energy and Utilities Board (the Board). In the Phase I application (the Application), ATCO Pipelines requested approval of a North, South, and Total revenue requirement. In previous applications, ATCO Pipelines had provided separate applications for its North and South service territories. The Application requested approval of a North revenue requirement of $140,589,000 for 2003 and $110,406,00 for 2004, a South revenue requirement of $42,118,000 for 2003 and $46,562,000 for 2004, and a Total revenue requirement of $182,707,000 for 2003 and $156,968,000 for 2004, all subject to adjustment for certain placeholder values.

A Notice of Hearing was published in the major Alberta newspapers on March 13, 2003, and was distributed by e-mail on March 13, 2003, to parties on the transmission transportation, ATCO Gas 2003/2004 GRA, NGTL 2003 tariff and NGTL CO_2 distribution lists. The notice of hearing set out the proposed schedule for this proceeding with the oral hearing to commence on June 16, 2003. By letter dated May 14, 2003, the Board subsequently revised the schedule and advised parties that the oral hearing would commence on June 23, 2003.

The public hearing convened in Calgary on June 23, 2003, before acting Board members Ms. C. Dahl Rees, M.A., LL.B., (chair), and Mr. M. W. Edwards, and Board member Mr. B. T. McManus, Q.C.

The Board considers that the record for this proceeding closed on September 3, 2003, following the receipt of written Argument and Reply on September 3, 2003.

1.1 Procedural Issues

By letter dated April 11, 2003, ATCO Pipelines requested approval to negotiate all Phase I and Phase II elements of the 2003 and 2004 revenue requirement and tariffs. The Board issued Decision 2003-035 on April 20, 2003, which permitted ATCO Pipelines to enter into negotiations with customers for 2003 items, but withheld permission for ATCO Pipelines to negotiate 2004 items. The Board noted that it was necessary to have a more extensive examination of the 2004 issues than would be possible in the review of a negotiated settlement in light of the length of time since the last ATCO Pipelines North GRA and in light of the competitive issues arising between ATCO Pipelines and Nova Gas Transmission Ltd. (NGTL). NGTL was also to be reviewed in a 2004 test year tariff application.

By letter dated May 30, 2003, ATCO Pipelines requested that the Board vary Decision 2003-035 to allow ATCO Pipelines and its customers to negotiate 2003 and 2004 depreciation matters, on

the grounds that this was an independent and specialized portion of the GRA. Further, negotiating depreciation for 2003 alone was not considered efficient. The Board issued a letter dated June 2, 2003, varying Decision 2003-035 to allow negotiations on 2004 depreciation issues. By letter dated June 13, 2003, ATCO Pipelines filed a settlement application on 2003 and 2004 depreciation matters (the Depreciation Settlement). Participating in the Depreciation Settlement were the City of Calgary, the City of Edmonton, Alberta Urban Municipalities Association, Federation of Alberta Gas Co-ops Ltd. and Gas Alberta Inc. On June 19, 2003, the Board sent a letter to parties indicating that there was sufficient evidence on the record to review the settlement without requiring depreciation experts to appear in the hearing.

With respect to cost of capital, the Board received a letter dated May 20, 2003, from ATCO Pipelines regarding the treatment of 2004 cost of capital matters. This letter had been provided to the Board in response to a letter from the division of the Board responsible for the Cost of Capital for Electric and Gas Utilities under the Board's Jurisdiction, Application No. 1271597 (the Generic Cost of Capital Proceeding), noting the options of dealing with 2004 cost of capital issues within either the generic proceeding or within already established GRA proceedings. The Board sought and received the views of interested parties on this issue.

In its letter of June 2, 2003, the ATCO Pipelines 2003-2004 GRA division of the Board directed that 2004 cost of capital matters would be addressed in the generic proceeding.

The Board also responded to a motion by Alberta Urban Municipalities Association, the City of Edmonton, and the Consumers Group (AUMA/EDM/CG) made on May 30, 2003, requesting that the issues related to the Muskeg River pipeline be segregated into a separate module. The Board sought and received the views of interested parties on this issue. The Board issued a letter dated June 10, 2003, granting the motion and setting aside consideration of the Muskeg River pipeline and related issues, as a separate module, to a later date following the compliance filing of ATCO Pipelines related to Decision 2003-040, Affiliate Transactions and Code of Conduct, Part B.

1.1.1 Use of 2002 Actuals – Closing Balances

Views of the Applicant

ATCO Pipelines argued that actual account balances should not be substituted for the plant in service opening balances that underlie the Application. ATCO Pipelines argued that it is concerned that the principle of prospective ratemaking and the use of forward test years not be eroded unfairly. ATCO Pipelines noted that certain interveners may suggest that forecast items should be updated by using the most recent information available at the time of the hearing, or potentially even at the time of the Board's decision. ATCO Pipelines suggested that the difficulty with this approach is that it can result in unfair "cherry-picking", where some items are adjusted while others, that may also have changed, are not. ATCO Pipelines argued that the only fair way to deal with this issue would be to effectively update the Application in its entirety at one or more times, an exercise that is costly and inefficient. ATCO Pipelines urged the Board to maintain its commitment to prospective rate-making when reaching its decision for this Application, as reflected in the following Board comments from Decision 2000-82.

> The Board is committed to prospective rate making. Yet, the Board acknowledges a number of situations where test years have been completed to various degrees prior to the hearing being held and/or the related decision being issued. In the Board's view,

> completing the hearing and decision after the end of the test year are within its power and consistent with the practice of the Board. Notwithstanding these exceptions, the Board makes every effort to preserve the forward test year with decisions that are not retrospective in nature or appearance.

While situations change so that forecast expenditures on some items thought necessary may not materialize, and other unanticipated expenditures are required, the relevant issue is whether the overall forecast of expenditures is reasonable. ATCO Pipelines submitted that as the Board has noted in the past, under prospective ratemaking "actual capital expenditures are not required, or even expected, to be identical to those approved by the Board for a test year."

With respect to closing balances, ATCO Pipelines noted that forecast total plant in service at December 31, 2002 was $530,966,000, and the actual total plant in service was $531,321,000, 0.07% higher than forecast at December 31, 2002.

ATCO Pipelines noted that North plant in service was higher than forecast by 1.4% and South plant in service was lower than forecast by 1.3%. ATCO Pipelines submitted that the variances at December 31, 2002 for total plant in service, North plant in service and South plant in service were not material.

Views of Interveners

AUMA/EDM/CG

In Decision 2001-97, concerning the ATCO Pipelines South (APS) 2001-02 GRA, AUMA/EDM/CG noted that the Board directed APS to reduce the 2001 test year opening balance of Property Plant and Equipment by $1.99 million to recognize actual capital expenditures in the year 2000. Referencing Decisions E89091 and U97065, the Board found "…the use of forecast data distorted the opening balances for the test period, when actual results were available." The Board issued a similar finding in Decision 2001-96, concerning ATCO Gas South's 2001/02 GRA and in the recently completed ATCO Gas 2003/04 GRA.

AUMA/EDM/CG submitted that the circumstances in this case are identical to those referenced in the above decisions. Consequently, AUMA/EDM/CG recommended that the Board direct ATCO Pipelines North (APN) and APS to include the 2002 actual closing balances as the appropriate starting point for the determination of the 2003 and 2004 rate base. Further, to eliminate unnecessary errors in the calculation of rate base, AUMA/EDM/CG argued that the 2003 and 2004 calculations should also incorporate 2002 actuals for all rate base related items such as accumulated depreciation and customer contributions. AUMA/EDM/CG noted ATCO Pipelines' submission that the variance between forecast and actual for "total plant in service" at December 31, 2002, was not material and should not be substituted for the forecasts. AUMA/EDM/CG argued that the use of actuals was to avoid any unnecessary distortion in the opening balances for the test period, to the extent actual numbers are available.

Calgary

Calgary argued that the Board has to keep in mind the reasons behind prospective ratemaking. Calgary submitted that prospective ratemaking was not instituted to give the utility "control" over the record such as to allow it to argue that the record becomes "frozen" at whatever date the utility selects for its filing, particularly when dealing with a utility that did not file until after the start of its test period. In fact, Calgary asserted that the main reason for prospective ratemaking

was to improve the fairness to utilities in a time of increasing inflation. Calgary submitted that prospective ratemaking was never intended to keep the Board from using the best available information when it makes its decision.

Furthermore, Calgary submitted, there are a number of substantive numerical changes to the forecasted data at the time of a Phase I compliance filing. Generally speaking, Calgary submitted that compliance filings involve changes based upon the Board's Phase I decision which include cost of capital, related income tax, rate base additions or opening plant balances, Operations and Maintenance (O&M), Administration and General (A&G) expenses and taxes. Thus in complying with a Phase I decision, Calgary argued that most major cost centres are impacted. When the utility is aware of known and measurable changes from the original forecast based on actual data or a combination of actual and revised forecast data for issues such as rate base additions, O&M, depreciation, taxes, income taxes etc., then the additional work to upgrade the forecast for the "best information available" will not constitute cherry picking, nor will it be inefficient or overly costly. Calgary submitted that the best database available should be before the Board when it reaches a final decision on any Phase I proceeding. Calgary submitted that the 2002 actual closing balances should be the opening balances for 2003. Failure to use the actual balances will result in inaccurate costs and revenue requirements for at least the next two years, if not longer.

CAPP

CAPP noted that ATCO Pipelines was concerned about potential erosion of prospective rate making and that it suggested that using the most current information may lead to cherry picking, that is, where only some items are adjusted and others are not. As a response, CAPP noted that ATCO Pipelines suggested it would be fair to update the Application in its entirety. Using the most recent information available was a responsible thing to do in CAPP's view. It is accepted regulatory practice that the best information available should be used, with the hope of obtaining the best result possible. CAPP also submitted that it was nonsensical to ask the Board to approve the costs of a $625,000 capital project (Bretona Loop) that, by ATCO Pipelines' own admission, has been cancelled.

Views of the Board

The Board notes ATCO Pipelines' submission that prior year actual closing balances should not be substituted for the plant in service opening balances for the test year period under prospective ratemaking and that variances between forecast and actual results were immaterial.

In Decisions U97065, dated October 31, 1997, and E89091, dated December 15, 1989, the Board concluded that the use of forecast data distorted the opening balances for the test period, when actual results were available. Also, in Decision 2001-97, the APS 2001/2002 GRA, the Board directed APS to reduce the 2001 test year opening balance of Property Plant and Equipment by $1.99 million to recognize actual capital expenditures in the year 2000. The Board considers it appropriate in this case to uphold its view in these prior decisions.

Accordingly, the Board directs ATCO Pipelines, in a refiling to their Decision (the Refiling), to set its 2003 opening balances for Property Plant and Equipment, Accumulated Depreciation, and Net Contributions for ATCO Pipelines Total, APN, and APS equal to the 2002 closing balances.

2 CAPITAL ASSETS

2.1 Rate Base

ATCO Pipelines forecast the mid-year total rate base in the amount of $537,925,000 in 2003, including $391,062,000 attributable to APN and $146,863,000 attributable to APS. In 2004, the total mid-year rate base was forecast in the amount of $549,942,000, including $397,790,000 attributable to APN and $152,152,000 attributable to APS.

2.1.1 Plant in Service

The net mid-year plant in service for 2003 was forecast in the amount of $537,678,000, including $390,504,000 attributable to APN and $147,174,000 attributable to APS. In 2004 the net mid-year plant in service was forecast in the amount of $543,947,000, including $394,281,000 attributable to APN and $149,666,000 attributable to APS.

2.1.2 Combining APN and APS Plant in Service

Views of the Applicant

ATCO Pipelines argued that sufficient information has been provided in this proceeding to track the record from a North/South basis to a combined Total basis. ATCO Pipelines submitted that there are no benefits which offset the administrative cost of continued separation of plant in service.

ATCO Pipelines argued that a combined revenue requirement was a stated objective in the Application. ATCO Pipelines argued that the reason for initially mentioning separately the North, South and Total revenue requirements was the possibility of negotiating a settlement. When this possibility ceased to exist, ATCO Pipelines argued that the rationale for maintaining separate revenue requirements also fell away. ATCO Pipelines presented extensive information by North, South and Total, which the interveners had a full opportunity to address in the hearing process. ATCO Pipelines submitted that its rationale for requesting approval for only the combined revenue requirement was consistent with the evidence as filed.

ATCO Pipelines noted that Calgary stated that it "understands that to date APN has been combined with ATCO Gas North (AGN) for reporting purposes and it is not clear whether separate accounts for each of APN and AGN have been maintained."[1] ATCO Pipelines argued that it is clear from CAPP.AP-2 and the Application that separate accounts for APN and APS have been maintained since 1999, consistent with the Board's direction in Decisions U99102 and U99130. ATCO Pipelines submitted that Calgary's allegation is unsupported by any evidence, is contrary to the only evidence on the record, and should be ignored by the Board.

Views of the Interveners

AUMA/EDM/CG submitted that the Board should determine a separate revenue requirement, including plant in service, rate base and other items of revenue requirement, for APN and APS for the Application. Whether a separation of the revenue requirements is required beyond 2005 is a subject that should be determined at the time of the filing of ATCO Pipelines' next Phase I GRA, which may be in 2005 or beyond. Such an approach would also be consistent with the treatment requested for ATCO Gas and allow for more consistent and readily reviewable data,

[1] Argument Calgary, p.1 of 86

particularly given the close link between transmission and distribution. It would also allow for a better understanding of the potential rate impacts between North and South, following completion of 2003/04 Phase II applications for each Utility. Therefore, AUMA/EDM/CG submitted that the Board should review the Application on a North and South basis and not allow any relaxation of current reporting requirements at this time.

At this time, AUMA/EDM/CG submitted that separate revenue requirements are required to properly evaluate the reasonableness of the Application. AUMA/EDM/CG submitted that the question of combined revenue requirements can be dealt with in ATCO Pipelines' next GRA in much the same manner as in the ATCO Gas 2003/2004 GRA.

Calgary

Calgary submitted that it understood that, to date, APN has been combined with AGN for reporting purposes and it was not clear whether separate accounts for each of APN and AGN had been maintained. Calgary submitted that ATCO Pipelines should comply with the requirements of Decisions U99102 and U99130 and maintain separate accounts for APS and APN for at least the full 4-year period. In Calgary's view, there are significant differences in cost structures between APS and APN that require segregation of the accounts and separate revenue requirements.

Views of the Board

The Board agrees that sufficient information was provided in this proceeding to track the record from a North/South basis to a combined Total basis. In subsequent sections of this Decision, the Board has determined that for depreciation and cost of capital, there are no significant differences between APN and APS. Therefore, the Board considers that it is reasonable to regard these costs based on determinants using the combined databases of APN and AGN.

In the Board's view, as the first step towards implementation of a single revenue requirement, there is a need to establish separate revenue requirements for North and South, and test the separate Cost of Service studies in ATCO Pipelines' Phase II application to determine the similarities or reasons for significant difference between the rates and rate structures in each region.

The Board considers that the directions from Decisions U99102 and U99130 instructing ATCO to maintain separate accounts for regulatory purposes until December 31, 2004 with respect to divisions for ATCO Gas North, ATCO Gas South, ATCO Pipelines North, and ATCO Pipelines South should continue to be upheld.

Based on the foregoing, the Board directs ATCO Pipelines, in its Refiling, to file the revenue requirement separately for North and South. The Board therefore expects that the outcome of this Phase I process will be the setting of separate revenue requirements for North and South, and that separate rates will be retained for North and South in the subsequent 2003/2004 Phase II.

In subsequent sections of this Decision, where the Board has made adjustments affecting the revenue requirement on a combined basis, it will be necessary for ATCO Pipelines to apportion the adjustments appropriately between North and South.

2.2 Capital Expenditures

ATCO Pipelines forecast capital expenditures for 2003 in the amount of $41,913,000, of which $30,014,000 was attributable to APN and $11,899,000 was attributable to APS. In 2004 capital expenditures were forecast in the amount of $29,403,000, of which $19,943,000 was attributable to APN and $9,460,000 was attributable to APS.

2.2.1 Case to be Met/Burden of Proof

Views of the Applicant

ATCO Pipelines submitted that the Applicant's burden of proof is to establish, on a balance of probabilities, that its expenditures and investment in rate base are prudently incurred. In establishing prudence, ATCO Pipelines submitted that the regulator should not substitute its judgment for that of the utility in the absence of evidence of wasteful or imprudent spending.

ATCO Pipelines argued that the National Energy Board (NEB) has long endorsed this principle, as summarized in the following definition from Brandeis J.'s separate opinion in *Missouri ex rel. Southwestern Bell Teleph. Co. v. Missouri Pub. Service Commission,* 262 IS.276, PUR 1923C 193, 67L Ed. 981, 43S Ct 544:

> The term "prudent investment" is not used in a critical sense. There should not be excluded from the finding of the base, investments which, under ordinary circumstances, would be deemed reasonable. The term is applied for the purpose of excluding what might be found to be dishonest or obviously wasteful or imprudent expenditures. Every investment may be assumed to have been made in the exercise of reasonable judgment, unless the contrary is shown.[2]

ATCO Pipelines submitted that the NEB has very recently reaffirmed its acceptance of the regulatory presumption of management in good faith when utilities budget and make operating expenditures.[3] ATCO Pipelines submitted that through the record of this proceeding, ATCO Pipelines has established, on a balance of probabilities, the prudence of its applied-for revenue requirement for test periods 2003 and 2004.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG noted ATCO Pipelines' acknowledgement that it bears the onus of proving its case; however, ATCO Pipelines went on to suggest there should be an underlying presumption that forecast expenditures are prudent based on "management in good faith".

AUMA/EDM/CG submitted that such an approach would put the onus of proving imprudence on the Board and interveners. This is clearly inconsistent with the practice before the EUB as developed under its enabling legislation. AUMA/EDM/CG argued that the onus is on the applicant and the established and approved test for inclusion in rate base is whether the applicant adequately demonstrated that an asset would be "used or required to be used".

2 In the Matter of Part II of Public Hearing Respecting Tariffs and Tolls Charged by Interprovincial Pipe Line Limited, NEB Reasons for Decision, December 1977, at page 3-9

3 TransCanada PipeLines Limited Tolls and Tariff, RH-1-2002, NEB Reasons for Decision, July 2003, at page 16

Calgary

Calgary noted that ATCO Pipelines introduced the concept of a "regulatory presumption of management in good faith" and referenced the *Southwestern Bell Telephone Co* v. *PSC of Missouri* case from 1923. Calgary argued that this position attempts to misdirect the Board's attention from the real issue, which is that ATCO Pipelines, as applicant, has the onus of proof. Calgary submitted that there is no presumption in regulatory law that ATCO Pipelines' forecasts are reasonable. That would be a reversal of the onus of proof. In their section dealing with "The Bases of Operating Expense Regulation" Garfield and Lovejoy[4] make the following observation:

> In determining the operating expenses allowable in the cost of service, the expenses incurred are presumed to be reasonable and necessary for efficient operation until proven otherwise. <u>In making rates for the future</u>, commissions have included in the expenses allowed amounts which have not been incurred but which can be anticipated with some degree of certainty.[5] (emphasis added)

Calgary submitted that the Board should note that the *Southwestern* case was decided at a time when the commission in question was apparently reviewing operating expenses that had already been incurred. This is a process similar to what the Board would undertake in a prudence review of a historical test year, and there is a certain logic to the proposition that a utility should be presumed to have acted in good faith when it has actually incurred expenditures. However, Calgary submitted that, when a utility is asking for "budget approval" for a forecast test year, there is no logical reason to apply a presumption of correctness to a utility budget, and that the utility properly has the onus of proof of establishing that its forecast expenditure should be relied on (the "degree of certainty" referenced above by Garfield and Lovejoy).

CAPP

CAPP argued that there is no question that the applicant bears the onus of proving its case. It is insufficient for ATCO Pipelines to attempt to rely upon a regulatory presumption of good faith as a method of proving its case. This would result is a situation where an applicant could attempt to rely on this presumption as a "reverse onus clause" so that the onus of proof would be on interveners to disprove the applicant's case rather than on the applicant to prove it.

CAPP submitted that this has never been the law in Alberta. While ATCO Pipelines noted that the NEB has long accepted the regulatory presumption of management good faith, the NEB itself stated as follows:

> While the Board accepts the regulatory presumption of management good faith when utilities budget and make operating expenditures, it is of the view that an applicant must be prepared to thoroughly explain individual budget line items. The applicant must also be prepared to justify increases in budgeted expenses from a Base Year to a Test Year, particularly when such increases are significant.[6]

CAPP argued that the regulatory presumption of management in good faith does not lessen the applicant's onus to thoroughly explain and justify its application.

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4 Public Utility Economics, Garfield, P.J. and Lovejoy, W.F, Prentice Hall, New Jersey, 1964 at pages 46 – 48, discussing, inter alia, the *Southwestern* v *PSC of Missouri case*

5 *ibid*, page 47

6 RH-1-2002, p. 16

Views of the Board

The Board is of the view that it is the applicant's responsibility to justify its application through the traditional regulatory process, and the concept of management in good faith does not negate or reduce its responsibility to thoroughly and adequately explain individual budget items.

2.2.2 Level and Justification of Major Capital Expenditures

Views of the Applicant

ATCO Pipelines submitted that in its Application and Information Responses, a significant amount of information and detail was provided to explain its capital expenditure forecasts. ATCO Pipelines argued that the forecasts provided were prepared based upon the best data available at the time the Application was filed and that the capital forecasts were reasonable, prudent, and should be approved as applied for.

ATCO Pipelines submitted that it has a benchmark of $500,000 to delineate a major project. Although the interveners filed no evidence on this issue, ATCO Pipelines believed that interveners implied in cross-examination that ATCO Pipelines should have provided business cases for all projects, regardless of size. Respectfully, ATCO Pipelines argued that this was not the directive of the Board in past decisions, and would be an inefficient use of the hearing process.

ATCO Pipelines noted that the City of Calgary suggested various thresholds for business cases on an "ad hoc" basis, according to the type of capital expenditure, as follows:

IT Expenditures	$300,000
Replacements	fairly high threshold
Improvement	$1,000,000 +
Growth	$1,000,000 +

ATCO Pipelines submitted that its $500,000 threshold is appropriate, as it mirrors ATCO Pipelines' internal threshold requirements. Given the significant amount of information provided in the Application and Information Responses, ATCO Pipelines argued that it has complied with the Board's direction in Decision 2001-97 to provide business case information for the established major project threshold.

In Reply Argument, ATCO Pipelines disagreed with the approach taken by the AUMA/EDM/CG with respect to recommendations for disallowances in the capital expenditure categories. To ATCO Pipelines, AUMA/EDM/CG appeared to be suggesting that the Board not only make a general disallowance, but that the Board also make disallowances with respect to specific individual projects. ATCO Pipelines submitted that such an approach is inappropriate, and should not be endorsed by the Board. ATCO Pipelines argued that in accordance with the regulatory presumption of management in good faith, the regulator should not substitute its judgment for that of the utility in the absence of evidence of wasteful or imprudent spending. ATCO Pipelines submitted that AUMA/EDM/CG have not provided any such evidence to support their recommended disallowance.

ATCO Pipelines noted that Calgary continued to put forth its own requirements for a "complete project business case" and alleged that ATCO Pipelines had not met Calgary's requirements for

business cases. ATCO Pipelines submitted that Calgary's requirements for a business case have not been tested, nor do they conform to the Board's requirements for business cases.

ATCO Pipelines agreed with Calgary and the AUMA/EDM/CG that it is appropriate to have a threshold above which business cases would be prepared. ATCO Pipelines noted AUMA/EDM/CG's support for Calgary's suggestion for business cases "for all future capital expenditures greater than $300,000." ATCO Pipelines noted that Calgary's recommendation for a $300,000 threshold was in respect of information technology (IT) projects, not all capital expenditures, and that Calgary's threshold for Improvement and Growth related expenditures was actually at the $1 million level. Furthermore, ATCO Pipelines submitted that AUMA/EDM/CG offered no justification for its recommended $300,000 threshold and presented no evidence during the proceedings to support this recommendation. No rationale was provided by Calgary for its recommended $300,000 threshold for IT projects.

ATCO Pipelines also submitted that its existing $500,000 threshold is appropriate and requested that this level of expenditure be maintained as the "business case" threshold.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG argued that for any regulated utility, there is always a need for justification of major capital investments based on adequate business cases as part of the ordinary course of regulation. In the specific circumstances of ATCO Pipelines, AUMA/EDM/CG submitted that the lack of adequate business case analyses has been, and continues to be, an ongoing and serious concern of the Board and interveners for the last several years.

Therefore, AUMA/EDM/CG recommended the Board adopt one of two classes of remedies for lack of adequate business case analysis:

Option A: The project not be approved for construction or, if already built or under construction, not be approved for inclusion in rate base during the test period; or

Option B: The project be approved, but only a %age of the investment proposed should be allowed for inclusion in rate base. Alternatively, the Board may impose an adjustment in risk compensation when establishing the rate of return to reflect the shift of risk to customers.

AUMA/EDM/CG submitted that the record is deficient as ATCO Pipelines failed to provide adequate justification for a number of capital projects, inconsistent with Board requirements from Decision 2000-9, as restated in Decision 2001-97.

AUMA/EDM/CG submitted that information concerning the need for a project, including any forecast demand and energy, project costing, alternatives and applicable revenues associated with the project, should ordinarily form the basis of any supporting business case for significant capital projects (i.e. $300,000 or greater). AUMA/EDM/CG argued that such data should not have to be ascertained through Information Requests or cross-examination and, in the absence of such information, the Board should consider disallowing the project. Alternatively, AUMA/EDM/CG suggested that the Board should only allow a %age of the proposed investment for inclusion in rate base or impose an adjustment in risk compensation when establishing the rate of return to reflect the shift of risk to customers.

For example, AUMA/EDM/CG noted that Calgary was asked to provide its comments on whether it would support a deferral of approval on capital expenditures where ATCO Pipelines failed to provide a cost benefit analysis or a business case. Calgary agreed with this proposal and suggested "…deferring the approval until there is appropriate business cases would ensure that there's appropriate business cases pretty quickly[7]." AUMA/EDM/CG supported the deferral of capital expenditure projects until proper business cases are presented.

Calgary

Calgary submitted that ATCO Pipelines did not provide business cases for its proposed projects. Although some of the expenditures provided a comparative cost, e.g. the Airdrie Heartland Lateral, while others presented some form of cost benefit analysis, the documentation could not properly be considered to constitute full business cases. Calgary argued that there is more to a "business case" than providing a limited amount of verbiage or data which ATCO Pipelines then alleged satisfied the requirements of Decision 2001-97. A proper business case must, of necessity, contain the level of explanation, data and analysis required to allow a party reviewing the business case to understand the basis for, and reasoning behind, the recommendations made. Calgary noted that over 50% of the capital expenditures in APS were in the category "general" for which there was little explanation. As noted in Decision 2000-9,[8] significant capital expenditures should be supported by business cases. If they are not supported, they should not be approved.

Calgary submitted that the specific contents of a business case will obviously vary with the amount involved and the subject matter, which is why Calgary suggested varying thresholds for the provision of business cases, as follows:

IT expenditures	$300,000
Replacements	fairly high threshold
Improvements	$1,000,000 +
Growth	$1,000,000 +

CAPP

CAPP asserted that capital expenditures should be rational, prudent and adequately supported by business case analyses, inclusive of cost benefit analyses, before they are approved for inclusion in rate base. CAPP argued that approval of Line Pack Management and Account Balancing should be delayed until shippers have been legitimately consulted and a cost/benefit analysis shows the net benefit of these expenditures.

The Federation and Gas Alberta Inc. (FGA)

FGA agreed with the general comments of the City of Calgary[9] and the AUMA/EDM/CG[10] with respect to the quality of the business cases provided in support of capital expenditures. FGA considered that, whereas ATCO Pipelines had attempted to identify the benefits in most cases for its major projects, these benefits were mostly qualitative and not quantitative. FGA agreed that "the Applicant's burden of proof is to establish, on a balance of probabilities, that its

7 T1408
8 Decision 2000-9, p. 161, Direction 16
9 Argument of the City of Calgary, p. 1
10 Argument of the AUMA/EDM/CG, pp. 6-7

expenditures and investment in rate base are prudently incurred." However, to properly balance the probabilities, it is necessary to know the probable dollar benefits in as well as the qualitative benefits.

FGA noted that ATCO Pipelines is one of the smaller utilities regulated by the Board. FGA suggested that it would be sufficient if the Board continued its directions from Decision 2001-97 with respect to supporting capital expenditures with a business case and added directions with respect to supporting quantitative data.

FGA noted the two options suggested by AUMA/EDM/CG for disposition of ATCO Pipelines' capital program. This was by no means an exhaustive list, in the view of FGA, as the Board could also place a portion or all of certain projects in a PHFFU account. However, FGA considered that the projects brought forward by ATCO Pipelines are of such a nature that they do not lend themselves to partitioning into used and required to be used versus imprudent or placement into PHFFU. FGA submitted that the Board should either accept or deny each project based on its overall merits and the information supplied by all parties.

Views of the Board

The Board notes that ATCO Pipelines argued that the information provided in the Application and Information Responses fully complied with the business case requirements set forth by the Board in Decision 2000-9 and Decision 2001-97.

The Board agrees with the interveners that ATCO Pipelines has failed to adequately comply with Board requirements for justification of major capital projects. In Decision 2001-97 (ATCO Pipelines South 2001-02 GRA), the Board stated:

> In future rate applications, the Board will require more detailed information from ATCO for all major capital projects, in accordance with the Board's direction in Decision 2000-9 as follows:
> - a detailed justification including demand, energy, and supply information;
> - a breakdown of the proposed cost;
> - the options considered and their economics; and
> - the need for the project. [p.20]

The Board considers that the requirements listed by the Board provide minimum criteria to be adopted by ATCO Pipelines when justifying the merits of capital projects in future applications.

The Board is concerned with ATCO Pipelines' continued disregard of Board directions to provide business cases justifying capital expenditures as directed in Decisions 2000-9 and 2001-97. The Board considers the unavailability of business cases to be problematic, as the lack of fundamental analysis limits the understanding of the interveners and the Board in respect of the proposed projects and the underlying economics, options, and justifications for the projects. Further, the Board observes that ATCO Pipelines continues to rely on qualitative support instead of quantitative analysis. Qualitative assessments provide little value in determining whether a project provides a net benefit to customers. The Board agrees that ATCO Pipelines supplied a description of the projects and related information in the Application, Information Requests, and Undertakings in the proceeding; however, the Board considers that in many cases, ATCO Pipelines failed to provide an adequate level of quantitative information to comply with Board requirements from Decision 2000-9 and Decision 2001-97. Therefore, the Board must consider

whether individual projects or proposals for expenditures are reasonable using the information available, which might be general in nature. The Board will exercise its judgment in each case as to the reasonableness of the proposed expenditure and as to any reduction in or denial of capital expenditures for the 2003 and 2004 test years.

With regard to the minimum cost threshold requiring ATCO Pipelines to conduct business case analyses, the Board continues to accept ATCO Pipelines' minimum cost threshold for major projects of $500,000; however, this threshold would not preclude the Board or interveners from requesting ATCO Pipelines to justify or provide better explanations or information in relation to smaller capital expenditures.

2.2.3 Transmission Growth

2.2.3.1 Transmission Facilities – General Provision North

New transmission facilities provide service to new producer and industrial customers as well as system expansion to accommodate growth in deliveries to ATCO Gas. Expenditure levels of $2,280,000 and $2,060,000 were forecast for 2003 and 2004 respectively. In 2003, $695,000 related to expansion for increased deliveries to ATCO Gas and $1,585,000 related to providing new facilities to serve producer and industrial consumers. For 2004, $390,000 was forecast for expansions to serve ATCO Gas requirements with $1,670,000 forecast for service to new producer and industrial customers.

Views of the Applicant

ATCO Pipelines noted that AUMA/EDM/CG suggested a decrease to ATCO Pipelines' forecasts in this category of 34% for 2003 and 27% for 2004. ATCO Pipelines submitted that these recommended disallowances were without foundation. ATCO Pipelines noted that the forecast general growth related expenditures are $2,280,000 and $2,060,000 for 2003 and 2004 respectively. ATCO Pipelines submitted that this is an approximate decrease in each of 2003 and 2004 of $1,000,000 from the 1999 to 2001 average, and approximately $500,000 less than the 1999 to 2002 average, as demonstrated by the data in the following table.[11]

Table 1. APN Transmission Growth General - Actual/Forecast Expenditures

($000)	1999 Actual	2000 Actual	2001 Actual	2002 Forecast
General Growth	3,142	3,419	2,746	1,508
1999 – 2001 Average			3,102	
1999 – 2002 Average				2,703

ATCO Pipelines argued that the forecast expenditures were on average 20% less than the four year average and 30% less than the 1999-2001 average, reflective of the reduced level of forecast new producer growth on the pipeline system.

ATCO Pipelines stated that AUMA/EDM/CG was incorrect in asserting that ATCO Pipelines had not included any incremental demand for industrials/producers. ATCO Pipelines noted that the responses to BR.AP-20(c) and BR.AP-37 clearly identified the new producer/industrial demand based revenues for 2003 and 2004. Also, the errata filed by ATCO Pipelines on June 20, 2003, highlighted this point. As such, ATCO Pipelines argued that revenues were included in the Application to support these Growth Capital Expenditures.

[11] Reply Argument of ATCO Pipelines, p. 5

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG submitted in its Argument that the following table shows a historical summary of APN's forecast and actual Transmission Growth General expenditures for the years 1999 through 2004, inclusive.

Table 2. APN Historical/Forecast Growth – General Capital Expenditures ($000)

99 A	00 F	00 A	01 F	01 A	02 F	02 A	03 F	04 F
3,142	N/A	3,419	N/A	2,746	1,508	1,490	2,280	2,060

Based on ATCO Pipelines' statements, the majority of the capital expenditures for the Growth–General category related to new facilities to service producer and industrial customers. AUMA/EDM/CG noted that ATCO Pipelines' response to AUMA.EDM-48(i) provided an explanation for the deviation between the 2002 forecast in the 03/04 GRA and the 2002 actuals. Specifically, ATCO Pipelines stated:

> This category is composed of many projects. The main driver for the deviation was the warmer than normal temperatures experienced – in the fall of 2002. This resulted in lower than forecast in-house and third party costs.

This explanation seemed inconsistent to AUMA/EDM/CG with the fact the large majority of expenditures were intended for producer and industrial customers.

AUMA/EDM/CG also noted that the Application indicated very few specific projects for provision of service to producer and industrial customers[12]. While ATCO Pipelines provided some detail of the forecast capital expenditures for the Growth-General category, there was no information on the number of new customers or TJ of new producer or industrial demand. AUMA/EDM/CG submitted that ATCO Pipelines did not provide sufficient information to justify the level of the forecast capital expenditures.

AUMA/EDM/CG also submitted that, given the small number of identified projects for producer and industrial customers, the significant declines in the amount of producer volume forecast by ATCO Pipelines and the lower level of actual general expenditures for 2002, the Board should only allow forecast Growth–General capital expenditures in the amounts of $1,500,000 for each of 2003 and 2004, similar to those of 2002. These amounts would be $780,000 and $560,000 less than the forecasts for APN for 2003 and 2004, respectively.

Views of the Board

The Board notes that ATCO Pipelines forecast a net decline in transportation revenue from each of its market segments and no specific new customers were forecast that required the construction of new facilities in the North. However, ATCO Pipelines did forecast some new producer/industrial demand growth, which could require some incremental new general facilities to be constructed in areas other than at the existing connections. The Board observes that the forecasts for 2003 and 2004 are above the actual expenditures for 2002, but are below the average of the actual expenditures in the years 1999-2002. In view of ATCO Pipelines' forecast

12 Table 2.3-2, p. 31

decline in transportation revenue and its forecast for no new customers, the Board considers that the forecasts for transmission growth-general expenditures for the 2003 and 2004 are excessive. Instead of accepting the expenditures as applied for by ATCO Pipelines, the Board considers it more reasonable to accept the forecasts proposed by AUMA/EDM/CG in the amount of $1,500,000 for each test year as being sufficient provision for general transmission growth.

2.2.3.2 Specific Facilities – Growth North

Dow Hydrocarbon

Views of the Applicant

The Dow Hydrocarbon project involves the installation of 6.8 km of 219 mm loop in 2003 in the amount of $3,982,000 to provide pipeline capacity for the incremental energy requirements at the plant. In addition, a 7.5 km 273 mm pipeline would be installed to facilitate Dow's requested increase in security of supply.

ATCO Pipelines submitted that the installation of these facilities was in accordance with the long-term (15-year) non-standard agreement between ATCO Pipelines and Dow. As outlined in the Application and BR.AP-46(b), a minimum annual charge of $717,000 would be applicable and would ensure ATCO Pipelines received revenues for the facilities installed. Also, should Dow terminate the Agreement after 15 years, Dow would be responsible for any undepreciated value of the facilities. Overall, ATCO Pipelines argued that the facilities and identified capital expenditure represented the least cost option to meet the service requested by Dow and were fully underpinned by the customer.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG submitted that the project should be approved as requested. In particular, AUMA/EDM/CG made note of the fact Dow executed an agreement with a 15 year term and a minimum annual charge of $717,000, relieving some concerns regarding stranded investment and lack of customer contribution. Further, AUMA/EDM/CG noted that Dow was also responsible for any remaining undepreciated value of the facilities should it leave the system after 15 years.

Views of the Board

The Board is satisfied that the Dow Hydrocarbon project is a reasonable proposal. The Board considers that concerns regarding stranded assets are mitigated by the executed agreement with Dow for a 15-year term that includes a minimum annual charge of $717,000, together with the obligation of Dow to pay for the undepreciated value of the facilities upon its termination of the contract after 15 years. Therefore, the Board approves the forecast expenditures for the project as filed.

Jasper NOP Upgrade Peers to Marlborough

Views of the Applicant

ATCO Pipelines proposed an upgrade in normal operating pressure (NOP) on the Peers to Marlborough segment of the Jasper transmission line in the amount of $2,860,000 for 2003. ATCO Pipelines submitted that it has experienced significant producer receipt growth on the

Jasper transmission system. However, ATCO Pipelines argued that the Jasper transmission pipeline is only 273 mm (10") in diameter and in order to accommodate incremental producer volumes, this NOP upgrade was required. In addition to the incremental producer receipt revenue generated by this mainline capacity expansion, ATCO Pipelines' delivery capacity to the Alliance Pipeline would be increased by an incremental 25 TJ/day. ATCO Pipelines argued that the project was justified on the incremental producer receipt volumes alone.

ATCO Pipelines noted that AUMA/EDM/CG alleged that ATCO Pipelines did not indicate it provided a business case with respect to the project; however, ATCO Pipelines provided a detailed breakdown of project costs in response to CG.AP-25 (g). The NOP Upgrade was forecast to cost $2,860,000 requiring an approximate annual cost of service of $486,000. The annual revenue stream for 12 TJ/day will be approximately $504,000.

ATCO Pipelines noted that AUMA/EDM/CG recommended a disallowance of $2,406,664 in respect of this project. ATCO Pipelines submitted that the basis for this recommendation was flawed, and should be given no weight by the Board. Although AUMA/EDM/CG specifically noted that the ATCO Pipelines Business Policy and Practices were "non-Board approved", ATCO Pipelines pointed out that the AUMA/EDM/CG then took the liberty of quoting and utilizing the "unapproved" investment policy calculation for customer specific facilities.

ATCO Pipelines stated that AUMA/EDM/CG wrongly characterized the Jasper NOP Upgrade Peers to Marlborough project as customer specific facilities. This segment of line to be upgraded actually had connections to Alliance Pipeline, NGTL, existing producer receipt points, and the Town of Edson. ATCO Pipelines referred to the substantial producer growth history on the pipeline and the capabilities of the line to deliver significant volumes to the Alliance Pipeline system. ATCO Pipelines submitted that the proposed project was reasonable and prudent and that no intervener had raised any substantive rationale for any disallowance.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG noted that the project is supported by a revenue stream, which can be terminated with twelve months notice. AUMA/EDM/CG considered that a project costing nearly $3,000,000 with annual revenues of $500,000 for potentially one year and one month or perhaps even two years, did not have a sufficient payback to warrant customers bearing the risk of stranded investment. AUMA/EDM/CG considered that the capital costs associated with the project should be protected contractually. AUMA/EDM/CG considered that the project should be included in rate base with a deemed contribution of $2,406,664 to be used to offset the project's capital cost.

Views of the Board

The Board agrees with ATCO Pipelines' submission that the NOP upgrade would increase delivery capacity at the Alliance Edson interconnect by 25 TJ/day, thereby providing a potential benefit to customers by the incremental revenue opportunity of $504,000, based on the existing Firm Service Receipt (FSR) toll in comparison to the annual cost of service for this project of $486,000. The Board also notes that the Jasper NOP Upgrade Peers to Marlborough project will result in an increase in the pipeline capacity by 12 TJ/day to the Peers compressor station. This volume may be transported from the Edson area to the Edmonton area markets, while also

potentially mitigating any loss of customers due to the limited capacity on the ATCO Pipelines system in the area. In addition, ATCO Pipelines has demonstrated that the Jasper transmission system has substantial producer growth history on the pipeline. The capability of the line to deliver significant volumes to the Alliance Pipeline system would provide the potential to generate additional revenues. The Board also notes that ATCO Pipelines has signed a Firm Service Receipt contract for 10 TJ in the Edson area, since January 1, 2003, and further notes the receipt volume growth from 57.7 TJ/day in January 2001 to 138.5 TJ/day in 2003 in the Edson area. Therefore, the Board is satisfied that the Jasper NOP Upgrade Peers to Marlborough would be a prudent expenditure.

The Board notes that the Jasper NOP Upgrade does have some degree of technical risks associated with testing higher operating pressures on the pipeline, but expects ATCO Pipelines to adequately address those risks.

The Board notes that AUMA/EDM/CG argued for a deemed contribution amount to be applied to the project based on its interpretation that the Upgrade is customer specific whereas ATCO Pipelines argued that the NOP Upgrade would benefit producers and delivery customers and potentially enhance incremental revenues, to the benefit of all customers. The Board considers that the Jasper NOP Upgrade Peers to Marlborough offers the benefits of additional revenues, capacity, and service to both receipt and delivery customers and therefore customer specific treatment or a deemed contribution would not be warranted.

Bretona Lateral Loop

Views of the Applicant

ATCO Pipelines requested approval for installation of a loop transmission line in the amount of $625,000 in 2004. While the Bretona Loop was originally determined to be required during the test periods, ATCO Pipelines stated that continuing assessment of this project resulted in a decision by ATCO Gas to install facilities to meet its requirements for less cost than ATCO Pipelines could. As a consequence, ATCO Pipelines indicated that it would not be expending the funds originally forecast in the test periods for the Bretona Loop. In accordance with prospective rate-making principles, ATCO Pipelines submitted that its overall forecast of capital expenditures was reasonable and prudent, and that approval of these forecast expenditures should not be affected by its decision not to proceed with the Bretona Loop.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG submitted that the amount associated with the Bretona Loop should be removed from the forecast of capital additions as ATCO Gas and not ATCO Pipelines is now undertaking the project. AUMA/EDM/CG also argued that ATCO Pipelines did not identify the fact ATCO Gas may be able to install facilities to meet the forecast need for less than ATCO Pipelines.

Calgary

Calgary submitted that under the ATCO Pipelines proposal both ATCO Pipelines and ATCO Gas would have the Bretona Loop in rate base together with all related costs including return, income tax, depreciation, and O&M. Calgary noted that in Decision 2000-9, the Board did not allow the inclusion in rate base of Carbon acreage protection as CWNG had confirmed that the

funds had not been expended, and, therefore, the amount could not pass the "used and useful" test. In Calgary's view those circumstances are indistinguishable from the Bretona Loop now that the Applicant has confirmed that the project will not proceed.

Views of the Board

The Board has considered ATCO Pipelines' argument that in accordance with prospective ratemaking principles, the cancelled Bretona Loop project should remain in rate base. However, the Board agrees with Calgary's position and considers that inclusion of the Bretona Loop would distort the forecast and would not meet the statutory rate base tests, when clearly the loop would not be installed and neither the capital cost nor any other associated cost would be related to a facility that was used or required to be used. Further, inclusion of costs associated with the Bretona Lateral Loop in the rate base of ATCO Pipelines would lead to a double counting of these costs, given that they would also be included in the rate base of ATCO Gas. Therefore, the Board denies the inclusion of the Bretona Loop in 2004 capital expenditures.

The Board considers that it is the responsibility of the utility to thoroughly demonstrate to its customers and to the Board that projects and expenditures are both prudent and used or required to be used. Should the Board find that these tests are not met, the Board will disallow all, or a portion of, the project from rate base.

2.2.3.3 Transmission Facilities – General Provision South

Expenditure levels of $1,398,000 and $1,315,000 were forecast for 2003 and 2004 respectively, for new transmission facilities to provide service to new producer and industrial customers as well as system expansions to accommodate growth in deliveries to ATCO Gas. Of the $1,398,000 forecast for 2003, $688,000 related to expansions for increased deliveries to ATCO Gas and $710,000 related to new facilities to serve producer and industrial consumers. For 2004, $500,000 is proposed for expansions to serve ATCO Gas requirements and $815,000 is proposed for service to new producer and industrial customers.

Views of the Applicant

ATCO Pipelines submitted that its methodology for forecasting general growth related expenditures is based on a three year historical average cost for each category tempered with judgment and an estimate of general growth of business activities.

ATCO Pipelines noted AUMA/EDM/CG's suggestion that the majority of expenditures for APS Growth Related Expenditures are for new facilities to service industrial and producer customers. ATCO Pipelines disagreed with such a conclusion. ATCO Pipelines noted that the breakdown between facilities at ATCO Gas and producer/industrial customers was provided in the Application as follows:

Table 3. APS Forecast Growth General (ATCO Gas & Producer Industrial)

	2003 ($000's)	2004 ($000's)
ATCO Gas	688	500
Producer/Industrial	710	815
Total	**1398**	**1315**

ATCO Pipelines submitted that while expenditures in 2004 are not an equal split, it is not an "overwhelming majority".

ATCO Pipelines noted that AUMA/EDM/CG have suggested 56% and 62% reductions to the ATCO Pipelines forecasts for 2003 and 2004 respectively. ATCO Pipelines argued that AUMA/EDM/CG attempted to justify these recommended decreases to the APS forecasts based upon an analysis of historical forecasting. ATCO Pipelines argued that the historical costs as identified by ATCO Pipelines in CAPP.AP-4 (1999 and 2000) and in the Application (2001 and 2002) were as follows:

Table 4. APS Historical Costs for General Growth ($000's)

	1999 Acutal	2000 Actual	2001 Actual	2002 Forecast
General Growth	1912	1770	1352	952
1999-2001 Average			1678	
1999-2002 Average				1497

ATCO Pipelines submitted that this table clearly demonstrated that average historical actual costs for capital expenditures in this category were significantly greater than those forecast for 2003 and 2004. ATCO Pipelines submitted that its forecasts were reasonable and that the disallowances recommended by AUMA/EDM/CG were inappropriate.

ATCO Pipelines noted AUMA/EDM/CG's suggestion in Argument that incremental revenues were not included in the Application to support the capital expenditures. Similar to the situation with APN, this was an incorrect assumption on behalf of AUMA/EDM/CG. ATCO Pipelines argued that BR.AP-20(c) and BR.AP-37 and the errata filed on June 20, 2003, identify that demand based revenues have been included.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG submitted that the following table shows a historical summary of APS' forecast and actual Transmission Growth–General expenditures for the years 1999 through 2004, inclusive. AUMA/EDM/CG showed the 2000, 2001 and 2002 forecasts from the 2001/02 APS GRA and the current 2003/04 ATCO Pipelines GRA.

Table 5. APS Historical/Forecast Growth – General Capital Expenditures ($000)

99 A	00 F	00 A	01 F	01 A	02 F	02 F	02 A	03 F	04 F
1,912	2,118	1,770	1,985	1,352	1,855	952	764	1,398	1,315

AUMA/EDM/CG submitted that an examination of the above table shows consistent over-forecasting. The 2000 actuals were 16% less than the 2000 forecast. The 2001 actuals were 32% less than the 2001 forecast. The 2002 actuals were 20% less than the 2002 forecast in the 2003/04 GRA. Further, APS' accuracy of forecasting appears to be worse in the second of the two test years based on a comparison of the 2001/02 GRA forecast to the actuals. That is, APS' forecasting bias and error increases the further out the forecast is. The 2001 actuals were 32% less than the 2001 forecast in the 2001/02 GRA, while the 2002 actuals were 59% less than the 2002 forecast in the 2001/02 GRA.

AUMA/EDM/CG argued that if the actuals for the years 1999 to 2002 were examined, there was a significant downward trend in actual capital expenditures. 2000 actuals were 7% less than 1999 actuals. 2001 actuals were 24% less than 2000 actuals. 2002 actuals were 43% less than 2001 actuals. The overall decline of capital expenditures in the Growth-General category for APS from 1999 to 2002 has been 60%, or an arithmetic average of 20% per year. AUMA/EDM/CG submitted that there is demonstrable and consistent over-forecasting that can simply not be explained away.

AUMA/EDM/CG submitted that APS did not adequately justify its capital expenditures for Growth – General assets and has consistently over-forecast the capital expenditures. Therefore, AUMA/EDM/CG recommended that the Board use the 2002 actual capital expenditures as the base and reduce the capital expenditures by 20% of the 2002 base for each of the test years. This results in recommended capital expenditures of 80% of $764,000 or $610,000 for 2003 and 80% of $610,000 or $500,000 for 2004. These amounts are $788,000 and $815,000 less than ATCO Pipelines' 2003 and 2004 forecasts, respectively, for the South.

Calgary

Calgary submitted that except for the previously noted lack of detail with respect to the "general" category, based upon the previous two years' experience the forecast capital expenditures for APS, while perhaps somewhat on the high side, do not appear to be unreasonable (exclusive of the Bretona Loop).

Views of the Board

The Board notes that ATCO Pipelines argued that the average historical actual costs for capital expenditures in this category are significantly greater than those forecast for 2003 and 2004. However, the Board agrees with the submission of the AUMA/EDM/CG that ATCO Pipelines has a history of over forecasting in this category. The Board directs ATCO Pipelines to reduce its 2003 and 2004 transmission growth general forecast in the South by 15% as a result of its past record of over forecasting. The Board also notes that this reduction is consistent with the downward trend of APS's actual growth related expenditures.

2.2.3.4 Specific Facilities – Growth South

Airdrie Heartland Lateral

Views of the Applicant

ATCO Pipelines forecast an expenditure in the amount of $830,000 in 2003 for the installation of a transmission lateral to Southwest Airdrie. ATCO Pipelines noted that the CCA and AUMA/EDM/CG stated that the peak demand for Airdrie was not examined in the ATCO Gas hearing because the ATCO Gas facilities cost was so insignificant. However, ATCO Pipelines noted that its Application was filed on February 14, 2003, and the Airdrie Heartland Lateral project was clearly identified therein as being required to meet ATCO Gas' requirements. ATCO Pipelines submitted that in the ATCO Gas proceeding, the CCA and AUMA/EDM/CG had ample opportunity to request information regarding the ATCO Gas specific facilities and to challenge the ATCO Gas forecasts supporting those facilities. ATCO Pipelines argued that this proceeding was not the appropriate venue to be testing the ATCO Gas forecasts.

ATCO Pipelines submitted that to support the forecast capital expenditure for the Airdrie Heartland lateral, it relied on its own reasonableness checks and information provided by ATCO Gas regarding growth in existing subdivisions, plus the new subdivisions of Coopers Crossing, Heartland and Luxstone, all in south and southwest Airdrie. ATCO Pipelines argued that it has in the past rejected an ATCO Gas election of contract demand, which caused ATCO Gas to review its numbers.

ATCO Pipelines noted that the FGA argued that "ATCO Gas determines the design peak of each of its delivery points and provides them to ATCO Pipelines. This is appropriate, as the distribution company will have the best information available for its business. An LDC should best know its own forecast for growth and the design factors required of its own systems."

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG submitted that the evidence did not support the need for the Airdrie Heartland project. Fundamental to the forecast was the demand requirements forecast by ATCO Gas for Airdrie, including the number and types of customers forecast to be added and forecast consumption per customer. AUMA/EDM/CG argued that this information was not provided in either the ATCO Gas or ATCO Pipelines hearings, and review of such information was clearly germane to any assessment of this project, particularly as the forecast demand was a considerable departure from actual consumption. AUMA/EDM/CG submitted that this project should be considered a candidate for application of one of the remedies it proposed in Argument for unsupported projects.

Views of the Board

The Board notes that the project is required in accordance with the agreement between ATCO Gas and ATCO Pipelines to meet ATCO Gas peak demand. The Board accepts that there is growth in this area. However, the Board agrees with AUMA/EDM/CG that fundamental to the forecast are the demand requirements forecast by ATCO Gas for Airdrie, including the number and types of customers forecast to be added and forecast consumption per customer. The Board has considered the Argument of AUMA/EDM/CG indicating that information on the ATCO Gas forecast was provided in neither the ATCO Gas nor the ATCO Pipelines hearings.

The Board considers that ATCO Pipelines is completely aware of its obligation to prove its case. In this instance, the Board agrees with AUMA/EDM/CG that ATCO Pipelines has failed to fully justify the project, as the ATCO Gas forecast which underpinned the viability of the project was not tested in the 2003/2004 ATCO Gas Phase I GRA proceeding, and ATCO Pipelines did not introduce evidence as to the underlying demand to justify the project in its own Phase I proceeding. The Board is of the view that ATCO Pipelines should expect that the Board and interveners would scrutinize any business transactions or capital expenditures that involve another division of the company or an affiliate.

Therefore, while the Board accepts that the Airdrie Heartland Lateral is needed, the Board considers that a reduction of 15% should be applied to this capital expenditure to reflect the lack of adequate justification provided in relation to this item. In future GRA proceedings where ATCO Gas forecasts are used as a rationale for additional transmission facilities, the Board expects, and directs, ATCO Pipelines to produce and file a study validating the findings of

ATCO Gas via a business case, to provide a witness of ATCO Gas or ATCO Pipelines to defend the ATCO Gas forecasts and to provide pertinent information showing that the proposed expenditures represent the optimum facilities to meet the demand.

2.2.4 Improvements

2.2.4.1 Transmission Improvements – General North

Transmission improvements are forecast to be $3,892,000 and $3,198,000 in 2003 and 2004 respectively. They include improvements to measurement stations, compressor stations, cavern facilities, upgrades to the existing Process Control equipment and improvements to odorization systems, as well as cathodic protection of the pipeline system.

Views of the Applicant

ATCO Pipelines' methodology for forecasting expenditures related to improvements is based on project specific requirements for internal labour and contract pricing and historical expenditures by category type to account for expenses that typically are unknown during budgeting. This information is tempered with judgment to ensure that factors such as age of facilities, operational issues, code changes and safety issues are adequately accounted for. Details of the general capital expenditures for improvement related projects for APN was provided by ATCO Pipelines in response to BR.AP-24(b). Additional forecast items are due to increased pipeline integrity assessment and inspection work, increased vault removals, and increased valve assemblies improvements.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG submitted that the following table shows a historical summary of APN's forecast and actual Transmission Improvement – General expenditures for the years 1999 through 2004, inclusive.

Table 6. APN Historical/Forecast Improvement – General Capital Expenditures ($000)

99 A	00 F	00 A	01 F	01 A	02 F	02 A	03 F	04 F
1,663	N/A	2,256	N/A	3,586	4,444	4,290	3,892	3,198

AUMA/EDM/CG noted that the actuals from 1999 to 2002 have increased significantly. However, AUMA/EDM/CG submitted that it did not oppose APN's forecast amounts shown for this category of capital expenditures.

Views of the Board

The Board notes that no interveners opposed these expenditures. The Board has reviewed APN's forecast expenditures for Transmission Improvements – General for the test years and is satisfied that the amounts are reasonable. Therefore, the Board approves the amounts of 3,389,000 and $3,198,000 for 2003 and 2004 respectively for the North.

2.2.4.2 Transmission Improvements – Specific Projects North

UFG Meter Stations

Views of the Applicant

ATCO Pipelines forecast the amounts of $5,415,000 and $5,480,000 for 2003 and 2004 respectively for the installation of UFG meters n APN. Prior to Board Decision 2003-042, the blended UFG was applicable to all customers on the ATCO Gas and ATCO Pipelines systems. Pursuant to Decision 2003-042, a mathematical allocation was established to ensure a fair and reasonable allocation of UFG between the ATCO Pipelines and ATCO Gas systems. ATCO Pipelines submitted that this interim mathematical allocation would reduce the cross-subsidization that was occurring where the Industrial/Producer customers were subsidizing UFG for the Core Customers.

As stated in Decision 2001-97, Board Decision 2003-042, and in cross-examination, an allocation methodology was an interim measure only. Usage of an allocation method in the long term would not allow for the identification of areas to reduce UFG levels. As recognized in the approval of UFG metering for the ATCO Pipelines South system, ATCO Pipelines considered that measurement was the definitive answer.

In addition to providing absolute and definitive levels of UFG on both systems, ATCO Pipelines argued that the installation of these meters would allow both ATCO Gas North and ATCO Pipelines North to identify areas where reductions in UFG could be made on the respective systems. Accordingly, ATCO Pipelines requested that the Board approve the installation of the metering.

AUMA/EDM/CG

AUMA/EDM/CG stated the appropriate allocation of the costs of UFG metering for rates remains to be resolved as a Phase II issue.

Views of the Board

The Board agrees with ATCO Pipelines' argument that the installation of UFG meters would allow both ATCO Gas North and ATCO Pipelines North to identify areas where reductions in UFG can be made on the respective systems, in addition to providing absolute and definitive levels of UFG on both systems. The Board also notes that it approved the installation of UFG meters for APS in Decision 2001-97 based on the same underlying principles. Therefore, the Board accepts ATCO Pipelines' forecast capital expenditures for UFG meters for APN as filed.

Jasper NOP Upgrade Carldale to Weldwood

Views of the Applicant

ATCO Pipelines forecast the requirement for an upgrade in operating pressure on the Cardale to Weldwood segment of the Jasper transmission line in the amount of $980,000 for 2003. ATCO Pipelines submitted that the primary driver of this project was to secure the link from Carldale to Weldwood, thereby ensuring an acceptable level of security of supply to the community of Jasper. In addition, there would be spin-off benefits from completing the upgrade, by reduced O&M and fuel cost for the compressor, and by the potential saving of cost impacts that would otherwise result from a failure.

ATCO Pipelines submitted that a more extensive examination of the record illustrated that it provided a business case for the Jasper NOP project, which met the Board's requirements for business cases as outlined in Decision 2001-97.

ATCO Pipelines argued that there was no evidence to support AUMA/EDM/CG's opinion that running a fifty-year old pipeline at a higher pressure has no effect on the security of supply. ATCO Pipelines stated that reliance on compression would not provide the same security of supply as operating a pipeline at higher pressures. ATCO Pipelines identified Hinton compression as a risk to the gas supply for the Town of Jasper.

Views of Interveners

AUMA/EDM/CG

AUMA/EDM/CG considered that running a fifty-year old pipeline at a higher pressure would not provide a greater level of security of supply than the operation of a compressor, nor was there any evidence indicating current operations of the line were unreliable. In this regard, AUMA/EDM/CG noted that the pressure must be maintained by compression at other points not controlled by ATCO Pipelines.

AUMA/EDM/CG argued that ATCO Pipelines did not provide any reasonable standard for evaluating security of supply. Arguably, any project would increase security of supply. A third back up compressor could also be added. However, this level of security of supply would be excessive and expensive. AUMA/EDM/CG considered that the NOP increase was unjustified based on the evidence, and it would not measurably increase security of supply.

AUMA/EDM/CG submitted that the O&M savings and fuel savings forecast by ATCO Pipelines to justify the cost of the NOP upgrade were materially lower than the annual carrying cost of the project in the initial years.

AUMA/EDM/CG argued that the pressure testing program, including pressure upgrades in other areas of the pipeline, was simply not worth the O&M savings forecast by ATCO Pipelines for the Carldale to Weldwood NOP upgrade, nor the incremental revenues less incremental costs for the Peers to Marlborough NOP upgrade.

Views of the Board

The Board notes that ATCO Pipelines submitted that while the primary driver of the project is to secure this link and thereby ensure an acceptable level of security of supply to the community of Jasper, there would also be spin-off benefits from completing the upgrade. The benefits included reductions of $40,000 in O&M, $32,000 in fuel costs for the compressor, and the potential saving of cost impacts that would otherwise result from a failure. The Board considers that this project is another instance in which ATCO Pipelines failed to provide a detailed business case. However, the Board notes that the main reason for the project expenditure would be to provide an increased security of supply for Jasper via the NOP upgrade versus the current reliance on compression. The Board considers that the inadequacy of the business case does not warrant rejection of the project where security of supply is a paramount concern and appears to be a reasonable concern in the circumstances. Therefore the Board accepts the Jasper NOP Upgrade Carldale to Weldwood as filed.

The Board notes that the Jasper NOP Upgrade does have some degree of technical risks associated with testing higher operating pressures on the pipeline, but expects ATCO Pipelines to adequately address those risks.

2.2.4.3 Transmission Improvements-General South

Transmission improvements were forecast in the amounts of $3,257,000 and $3,588,000 in 2003 and 2004 respectively. The forecast amounts provided for improvements to measurement stations, compressor stations and cavern facilities, as well as cathodic protection of the pipeline system, upgrades to the existing Process Control equipment and improvements to odorization systems.

Views of the Applicant

ATCO Pipelines argued that its methodology for forecasting expenditures related to improvements was based on project specific requirements for internal labour and contract pricing and historical expenditures by category type to account for expenses that were unknown during budgeting. This information was tempered with judgment to ensure that factors such as age of facilities, operational issues, code changes and safety issues were adequately accounted for. Additional forecast items were due to increased pipeline integrity assessment and inspection work, increased vaults removals, and increased valve assemblies improvements.

ATCO Pipelines disagreed with Calgary's suggestion that it provided little detail or explanation in respect of APS improvement related expenditures. In its Application and responses to Information Requests, ATCO Pipelines submitted that it provided the following detailed information with respect to the proposed improvement expenditures for APS:

- improvements to measurement stations to increase operability
- installation of new valve assemblies to facilitate internal inspection
- compressor station improvements to ensure ongoing reliability
- cathodic protection improvements to ensure ongoing integrity of the pipeline system
- upgrades to existing process control equipment
- improvements to odorization systems.

ATCO Pipelines submitted that there was no evidentiary support for Calgary's recommendation to reduce the forecasts between 30% and 50%, nor was there any justification for the recommendation of AUMA/EDM/CG for a 13% reduction in 2003, and a 21% reduction for 2004. ATCO Pipelines argued that the AUMA/EDM/CG recommendation did not even allow for inflationary factors. ATCO Pipelines submitted that its forecast expenditures were appropriate and justified for the test years, and requested approval for $3,257,000 in 2003 and $3,588,000 in 2004.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG submitted that the following table showed a historical summary of APS' forecast and actual Transmission Improvement–General expenditures for the years 1999 through 2004, inclusive.

Table 7. APS Historical/Forecast Improvement – General Capital Expenditures ($000)

99 A	00 F	00 A	01 F	01 A	02 F	02 F	02 A	03 F	04 F
1,276	714	294	789	1,113	1,155	3,198	2,821	3,257	3,588

AUMA/EDM/CG submitted that an examination of APS' forecasting record in the above table showed significant over-forecasting in 2000 of 59%, and significant under-forecasting for 2001 of 41%. Even if one combined the two years on the assumption that capital expenditures might be delayed, the amount of over-forecasting was still 6% for the two-year period. AUMA/EDM/CG argued that the significant increase in the 2002 forecast in the 2003/04 GRA compared to the same year in the 2001/02 GRA was never explained, nor was the overall reason for the increase in capital expenditures between 2002 and 2004.

AUMA/EDM/CG submitted that ATCO Pipelines' forecasting record for this category was inconsistent from one year to the next and was not justified for the test years. AUMA/EDM/CG recommended that the Board use the 2002 actual capital expenditures as the base, and therefore, only allow an amount equal to the $2,821,000 expended in 2002 for the two test years 2003 and 2004. These amounts would be $436,000 and $767,000 less than ATCO Pipelines' forecasts for 2003 and 2004, respectively.

Calgary

Calgary submitted that over 50% of the APS improvement related expenditures are related to information technology, being the Line Pack Management, Customer Account Balancing and Information Systems. The vast majority of the remainder fell into the category of "general" for which there was little explanation. Further, the forecasts were over 50% higher than the average of the previous two years actuals. Calgary recommended that the Board reduce the forecasts by between 30% and 50% depending upon the Board's view of inflationary pressures on construction projects.

Views of the Board

The Board agrees with AUMA/EDM/CG that ATCO Pipelines' forecasting record for this category has been inconsistent from one year to the next, and considers that the 2002 actuals provide a reasonable base for future expenditures. The Board considers that ATCO Pipelines failed to justify an increase from 2002 actuals for the 2003 and 2004 test years, and believes that an amount based on the 2002 actual expenditures, as adjusted by 3.15% for inflation for both 2003 and 2004, in accordance with Board findings on inflation in Section 4.1 of this Decision, would be appropriate. Therefore, the Board approves the amounts of $2,910,000 and $3,000,000 for 2003 and 2004, respectively.

2.2.4.4 Transmission Improvements North and South

Line Pack Management

Views of the Applicant

ATCO Pipelines proposed the acquisition of a system to improve their management of Line Pack, in the amount of $715,000 for APN and $690,000 for APS for 2003. ATCO Pipelines submitted that the installation or upgrade of measurement facilities at thirteen key locations on the pipeline system (eight North, five South) will uncouple segments of its pipeline system that currently cannot be accurately modeled. ATCO Pipelines argued that knowledge of the current

Line Pack level in individual "decoupled" pipeline segments would allow it to better decide whether additional gas volumes should be brought on or taken off the pipeline system, thereby optimizing system operations and minimizing capital expenditures. ATCO Pipelines asserted that the availability of this information and the ability to decouple segments of the pipeline system would enable it to: (i) optimize assets on a segregated basis without installation of looping or other facilities; (ii) look for additional savings in UFG; and (iii) delve deeper into its pipeline network.

ATCO Pipelines submitted that the ability to better manage Line Pack and reduce swings in Line Pack would reduce the impact of price volatility and should minimize the swings in the total price of Line Pack purchased or sold. ATCO Pipelines indicated that Line Pack variations are one component of its net system imbalance and impacted ATCO Gas' deferred gas account positively or negatively. ATCO Pipelines argued that this was an issue of cross-subsidization.

ATCO Pipelines argued that that there is no basis, as suggested by CAPP, upon which to defer this project since CAPP did not raise an issue regarding the need for the Line Pack facilities. ATCO Pipelines submitted that there is a need for the applied-for facilities, and that it has provided its cost/benefit analysis in the Application, in accordance with Board directions. ATCO Pipelines recognized that while consultation may be desirable as part of an implementation process, the decision as to whether or not the expenditures related to the Line Pack project were prudent was the only matter for this proceeding.

ATCO Pipelines submitted that its expenditures related to its transition to a stand-alone transmission company have been prudently incurred under a workable plan that commenced in 1999 with the formation of ATCO Pipelines, later followed by the UFG meter program commenced in 2001. ATCO Pipelines argued that it has now evolved sufficiently to undertake the Line Pack Management and Customer Account Balancing programs. ATCO Pipelines submitted that it must be allowed to make prudent expenditures related to industry-standard transmission pipeline operating conditions.

In Reply Argument, ATCO Pipelines noted that FGA stated that the project "...is increasingly necessary as the value of the Line Pack increases" and ultimately recommended that the project be approved on the condition that ATCO Pipelines submit, at the time of its next GRA, evidence regarding the costs and benefits associated with its implementation.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG noted that CAPP's evidence indicated that ATCO Pipelines failed to provide adequate information for parties to evaluate Line Pack management capital costs and any benefit from the expenditures. A cost benefit analysis was not produced. AUMA/EDM/CG also noted that CAPP indicated the system was not broken and the $10,000,000 cost of the Line Pack Management and Customer Accounting Balancing programs was an "extremely large cost" relative to the potential benefits.

AUMA/EDM/CG argued that ATCO Pipelines failed to demonstrate that the project was necessary, or would provide benefits to customers commensurate with the cost. Nor was a cost benefit analysis or a business case submitted to justify the project. Therefore, AUMA/EDM/CG submitted that the project should be disallowed.

CAPP

CAPP argued that the proposed expenditures in relation to these items should not be approved, unless and until, a proper economic analysis indicating the relative cost/benefit of the project was prepared and provided to customers. CAPP noted that ATCO Pipelines suggested in argument that the Line Pack Management expenditures would:

i. Minimize line pack;
ii. Allow ATCO Pipelines to model more stringently;
iii. Reduce purchase and sale of line pack inventory;
iv. Minimize line pack swings on the system;
v. Minimize impacts to all ATCO Pipelines customers;
vi. Decouple segments of the system;
vii. Optimize assets without looping or other (new) facilities;
viii. Allow ATCO Pipelines to look for savings in UFG;
ix. Delve deeper into the ATCO Pipelines pipeline network.

CAPP submitted that of the nine benefits described, eight really amount to the same thing, that greater information would allow ATCO Pipelines to better manage line pack. In the absence of a cost/benefit study; however, CAPP submitted that it still did not know whether the status quo costs would be reduced enough to justify the proposed expenditures.

CAPP noted that ATCO Pipelines also suggested that deferral of this project would delay ATCO Pipelines' evolution to a stand-alone pipeline company. CAPP argued that ATCO Pipelines was a stand-alone pipeline company; at least that is the basis of its application in respect of capital structure and rate of return. If ATCO Pipelines now suggested it was not a stand-alone pipeline company, then CAPP asserted that it would be appropriate for it to revise its application in respect of both the requested capital structure and rate of return.

FGA

FGA acknowledged that the proposed Line Pack Management program might improve the operational capabilities of the ATCO Pipelines system. FGA submitted that, before embarking on this project, ATCO Pipelines should be required to clearly define its assumptions respecting projected savings and define the benefits, both tangible and intangible, in a coherent business case. FGA submitted that this project was increasingly necessary as the value of the line pack increased, and considered that the project should be approved on the condition that ATCO Pipelines submit, at the time of its next GRA, evidence on the costs and benefits associated with its implementation.

Concerning quantifiable benefits, FGA submitted that any losses or gains on the sale of line pack would probably even out over time. FGA submitted that the purchase and better management of line pack should benefit customers through reduced UFG from this source.

Views of the Board

The Board agrees with ATCO Pipelines that the installation or upgrade of measurement facilities at thirteen key locations on the pipeline system (eight North, five South) would uncouple

segments of the ATCO Pipelines pipeline system that ATCO Pipelines states cannot be accurately modeled at present.

The Board also notes ATCO Pipelines' argument that the availability of this information and the ability to decouple segments of the pipeline system would enable it to: (i) optimize assets on a segregated basis without installation of looping or other facilities; (ii) look for additional savings in UFG; and (iii) delve deeper into the ATCO Pipelines pipeline network. ATCO Pipelines submitted that the ability to better manage line pack and reduce swings in line pack would reduce the impact of price volatility and should minimize the swings in the total price of line pack purchased or sold. However, the Board considers that all of the preceding statements justifying the benefits are qualitative in nature and do not provide substantive or even probable grounds for cost savings.

The Board agrees with AUMA/EDM/CG that ATCO Pipelines did not demonstrate that this project was necessary or would provide benefits to customers commensurate with the cost, nor was a cost benefit analysis or a business case prepared for the project. The Board also notes CAPP's argument that the proposed expenditures should not be approved unless and until a proper economic analysis indicating the relative cost/benefit of the project has been prepared and provided to customers. The Board considers that ATCO Pipelines has failed to justify the Line Pack Management expenditures and benefit to customers as per the Board's requirements from Decision 2000-9 and restated in Decision 2001-97.

The Board therefore denies the inclusion of the Line Pack Management program for the 2003 and 2004 test years.

Customer Account Balancing

Views of the Applicant

ATCO Pipelines proposed the acquisition of Customer Account Balancing equipment in 2003 for the amounts of $2,200,000 for APN and $500,000 for APS and $2,200,000 for APN in 2004. ATCO Pipelines noted that no intervener opposed the need for Customer Account Balancing equipment. ATCO Pipelines argued that customer requests for more timely and accurate information have been noted in the ATCO Pipelines'[13] evidence and acknowledged by CAPP[14] in its evidence, where CAPP confirms that "some producers have asked for earlier and better account balance information; CAPP members have been present at ATCO meetings where such requests were made."

ATCO Pipelines argued that the installation of SCADA at all connections between ATCO Pipelines and ATCO Gas with flow in excess of 35,000 scf/hr, upgrades to Transportation Information System (TIS) and staff additions to manage system balancing, would result in an overall net benefit to the ATCO Pipelines system in terms of fairness to customers. ATCO Pipelines submitted that improving customer account balancing accuracy would minimize impacts on other customers and interconnecting pipelines.

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13 Application, Section 2-3, p. 12 of 33, lines 12-15; Exhibit 2-07 – ATCO Pipelines Response to AUMA/EDM/CG.AP-15(f)

14 Exhibit 10-07 – Written Evidence of CAPP, p. 14, lines 4-8

ATCO Pipelines argued that its evolution to a stand-alone pipeline company requires more stringent daily account balancing to ensure that all customers are held accountable for their activities and to ensure that those activities would have minimal impact on other customers. Other pipeline companies require their customers to balance daily and this proposed expenditure would move ATCO Pipelines towards the industry standard.

ATCO Pipelines noted that CAPP's only suggestion with respect to the forecast expenditures was for a deferral of the expenditures until shippers were satisfied "that such investments and O&M expenditures will create significant value for shippers". ATCO Pipelines confirmed its intentions to seek customer input in the development of the Customer Account Balancing mechanisms and tolerances.

ATCO Pipelines noted that Calgary's apparent concern respecting $2 million of the TIS project, which relates to customer account balancing was clearly based on a fundamental misunderstanding of ATCO Pipelines' tariff balancing provisions. In cross-examination, Mr. Johnston stated his *understanding* that "most pipelines now have daily balancing so one would have thought that there was software you could pick up, essentially, off the street and deal with that issue."[15]

ATCO Pipelines submitted that Calgary's clear lack of understanding of the upgrades required for TIS as an integral, multipurpose information system, and Calgary's mistaken assertion that ATCO Pipelines already had a daily balancing tolerance level, supported ATCO Pipelines' submission that Calgary's evidence respecting the Customer Account Balancing project should be given no weight by the Board. ATCO Pipelines submitted that the Customer Account Balancing project was required to provide fair, accountable, timely and accurate service to all customers, and that the associated capital expenditures were both reasonable and prudent.

ATCO Pipelines agreed with Calgary that shippers should be totally responsible for balancing their own accounts. Further, shippers need accurate information from which to balance. The acquisition and dissemination of more timely and accurate account information would be provided via the implementation of the Customer Account Balancing project. ATCO Pipelines argued that shippers would be required to balance to more stringent tolerance levels, to minimize the impact of imbalances on others.

Views of the Interveners

AUMA/EDM/CG

As with the Line Pack Management project, AUMA/EDM/CG noted that CAPP's evidence indicated ATCO Pipelines did not provide adequate information for parties to evaluate the costs for account balancing, nor did ATCO Pipelines provide any evidence indicating customers would receive any benefit from the expenditures since a cost benefit analysis had not been produced. AUMA/EDM/CG submitted that there was no evidence indicating the project was necessary or would provide benefits to customers. Therefore, AUMA/EDM/CG submitted that the project should be removed from the capital expenditure forecast for both North and South.

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15 Tr., Volume 12, p. 1372, line 23 and p. 1373, line 1

Calgary

Calgary noted that in the 1998 CWNG Phase II GRA (CWNG at that time was comprised of both distribution and transmission functions) CWNG testified[16], that balancing was a simple concept. The key was what was taken off the system by the customer and what was put on the system by the customer. Calgary argued that ATCO Pipelines had not explained what had changed so dramatically since 1999 to justify the IT expenditures requested for balancing. Calgary submitted that ATCO Pipelines had not met its burden of proof by providing a full and detailed description of the changes in balancing requirements since 1999, nor had it provided the business case documenting the changes since 1999. Calgary recommended that the requested expenditure be denied.

CAPP

CAPP neither supported nor opposed ATCO Pipelines' attempt to change its line pack management and account balancing systems. However, CAPP objected to ATCO Pipelines undertaking projects of this magnitude (approximately $10 million inclusive of O&M) without either adequate justification or the consultation and involvement of shippers. CAPP argued that ATCO Pipelines failed to produce a cost benefit analysis for the aforementioned costs. Therefore, CAPP submitted that these items should be deferred until ATCO Pipelines consulted with shippers and conducted a cost/benefit analysis that showed significant value to customers or ATCO Pipelines.

CAPP noted ATCO Pipelines' argument that more stringent customer account balancing was required to ensure that any imbalances that slopped over to the distribution company from industrial and producer customers was more appropriately managed. CAPP noted that ATCO Pipelines acknowledged it had accurate metering in place at all locations where gas was received by or delivered off its system from producers and industrials. It also acknowledged that with two minor exceptions, all customers had balanced within acceptable ranges in the past year. CAPP argued that it did not see that the need for greater account balancing had been established, nor that the benefits of the proposed expenditures would justify the costs.

CAPP noted ATCO Pipelines' suggestion that with the installation of these new facilities, it would be able to manage the line pack required in various parts of the system more stringently because it would be able to model various parts of the system individually. CAPP again noted that ATCO Pipelines failed to justify this assertion.

Views of the Board

The Board notes ATCO Pipelines' submission that customers and interconnecting pipelines requested more stringent and timely customer account balancing information. However, the Board agrees with the submissions of interveners that ATCO Pipelines failed to submit an adequate business case that showed both the cost and benefits of the proposed project to customers. The Board has considered ATCO Pipelines' argument that other pipelines require their customers to balance daily and its implication that this is an industry standard approach. However, this does not mitigate the Applicant's burden to justify the customer account balancing capital expenditure via a cost/benefit or business case analysis.

[16] Tr. pp. 1763 - 1764

Since a number of interveners opposed the Line Pack Management and Customer Account Balancing projects on the basis of inadequate justification of the projects and their benefits, it would appear to the Board that the customers who are impacted by potential problems of cross subsidization and fairness have determined that the benefits of alleviating or addressing these problems do not outweigh the costs of the projects, at least as shown on the record of this proceeding.

While the Board agrees with the notion that customers require timely and accurate information to properly balance their accounts on a daily basis, the Board is not persuaded that the forecast costs are properly justified.

Therefore, the Board denies the inclusion of customer account balancing capital expenditure costs for the 2003 and 2004 test years.

Information Systems

Views of the Applicant

ATCO Pipelines proposed the acquisition of programs to enhance their XP and TIS in the amounts of $2,500,000 for each APN and APS in 2003 and $500,000 for each of APN and APS in 2004. ATCO Pipelines submitted that the ATCO Group presented a business case in respect of the XP Project that complied with the Board's directions in Decision 2001-97 in consultation with the affected companies, including ATCO Pipelines. ATCO Pipelines argued that it was clear that software packages no longer supported by the vendor must be replaced in order for business operations to continue.

ATCO Pipelines noted that AUMA/EDM/CG recommended the disallowance of $540,000 for the conversion to the XP Upgrade solely based on their allegation that ATCO Pipelines failed to consider all alternatives to the XP upgrade. In particular, AUMA/EDM/CG alleged that ATCO Pipelines did not specifically state that it considered the continued use of Windows NT on a fee-for-service basis as an alternative to the XP upgrade. ATCO Pipelines suggested that this allegation was inconsistent with the evidence.

ATCO Pipelines submitted that it would be inefficient to require a listing of each and every alternative, such as converting to manual systems, using adding machines, paying a fee per service to support broadly used software, all of which could be quickly discounted by ATCO Pipelines.

Furthermore, ATCO Pipelines argued that if AUMA/EDM/CG was of the view that supporting Windows NT on a fee-for-service basis would be a lower cost alternative, then, those fees should be included in the revenue requirement. However, ATCO Pipelines noted that no evidence was provided by AUMA/EDM/CG on the issue, and furthermore, no intervener provided any evidence that the fee-for-service option would result in lower costs. ATCO Pipelines argued that it completed an assessment that concluded that reasonable costs were incurred by ATCO Pipelines for the XP software. ATCO Pipelines submitted that accepting the recommendation of the AUMA/EDM/CG would result in higher costs to customers and should be disregarded by the Board.

ATCO Pipelines submitted that it presented a business case in respect of the TIS project that complied with the Board's directions in Decision 2001-97. ATCO Pipelines argued that the

business case for TIS is based on an existing key billing and customer information system, which had an outdated programming language causing the company to experience numerous problems and outages. ATCO Pipelines argued that it could not function without this being corrected. ATCO Pipelines argued that the benefits of the TIS were "blatantly obvious" in terms of the status of the existing ATCO Pipelines system and in terms of the remedy required to maintain a reliable and secure customer information and billing system. ATCO Pipelines argued that since this was an existing system that was specifically built to handle ATCO Pipelines unique data and measurement sources, it was not the type of system for which a third party software package was available to economically meet the business requirements.

For the TIS project, ATCO Pipelines provided the following information in compliance with the Board's directions in Decision 2001-97:

1. Justification – "Centura is an outdated programming language, need to utilize current technology in order to be able to continue operating. Current hardware and software tools are outdated and needs to be brought up to current technology."

2. Breakdown of the project cost – "Forecast expenditures are $2,300,000 in 2003 and $430,000 in 2004."

3. Options considered & economics – "The alternative in each case is to do nothing but this would not allow ATCO Pipelines to meet business requirements."

4. Need – "Enhance TIS to allow ATCO Pipelines to satisfy business requirements as follows:

    Conversion from Centura to VB.net. Centura is an outdated programming language, need to utilize current technology in order to be able to continue operating.

    UFG tracking is required to allow ATCO Pipelines to accurately track and report on UFG.

    Changes are required to ensure accurate tracking of system balances.

    Enhance TIS On-line to allow ATCO Pipelines to satisfy business requirements as follows:

    Current hardware and software tools are outdated and need to be brought up to current technology.

    On-line contracting is required by customers to make changes to their contracts using the Internet."

In reply, ATCO Pipelines noted Calgary's allegation that "ATCO Pipelines does not have a formalized, written business case process." ATCO Pipelines submitted that business cases were provided for all projects over $500,000.

ATCO Pipelines noted that Calgary went on to state that "ATCO Pipelines is not aware of or is not utilizing the I-Tek PMO office and its statement of work or business case delivery capability." ATCO Pipelines argued that this statement was contrary to the evidence. Calgary themselves provided evidence of the ATCO Group statement of work and business case for the XP project, however, ATCO Pipelines confirmed there was not a separate statement of work and

business case for ATCO Pipelines. ATCO Pipelines noted that it was involved in determining the reasonableness of the XP upgrade project and its cost.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG noted that ATCO Pipelines did not provide any information on the alternative of continuing Windows NT service for a fee. AUMA/EDM/CG asserted that ATCO Pipelines did not provide the appropriate business case, including the alternatives for the Windows XP project. Therefore, AUMA/EDM/CG argued that the amount requested should be disallowed.

AUMA/EDM/CG was also concerned about the lack of detail in relation to the cost components for the proposed project. For example, AUMA/EDM/CG submitted that it would be beneficial to have information concerning the number of personal computers and servers being upgraded and the cost per unit. Information concerning software implementation and training costs would also be of assistance in reviewing projects of this nature. AUMA/EDM/CG submitted that such information should properly be part of a reasonable business case in support of a proposed project of this nature. Further, alternatives such as continued use of the existing operating system and its applicable cost should also form part of such a business analysis and be provided to the Board and interveners for consideration.

AUMA/EDM/CG noted that a number of parties gave ATCO Pipelines significant and ample opportunity to further explain and justify the proposed TIS expenditures. For example, in cross-examination by CAPP, ATCO Pipelines confirmed that the TIS Enhancement (General and On-Line) capital expenditures were part of the bigger Line Pack Management and Customer Account Balancing projects totaling $10,000,000, including approximately $8,500,000 of capital expenditures and $1,500,000 of O&M. In further cross-examination by CAPP, AUMA/EDM/CG noted that ATCO Pipelines confirmed the issues related to this project did not relate to pipeline integrity or safety. Instead, the upgrades were stated to be a part of "…a continuation of the evolution of our company, to a stand-alone pipeline company." When questioned by CAPP about whether a cost-benefit analysis had been completed for the project, AUMA/EDM/CG noted that ATCO Pipelines responded there was "…no net benefit, that it was a cross subsidization issue between customers."

AUMA/EDM/CG noted that Calgary also cross-examined ATCO Pipelines on the role of I-Tek in the TIS project. ATCO Pipelines, during Calgary cross-examination, confirmed it did not have a formalized procedure for the development of business cases. For uniquely identified capital projects over $500,000, ATCO Pipelines indicated a "general rule of thumb" would require a general description or purpose of the project including the cost, benefits and alternatives. On the more specific topic of the TIS project, ATCO Pipelines confirmed it was the sponsor of the TIS project, though ATCO I-Tek would be providing some training for employees.

AUMA/EDM/CG submitted that ATCO Pipelines' lack of awareness of the importance of submitting business cases, its view that the type of investment for the TIS project did not require business cases to be done and the fact that there was not a formal business case model nor available staff to perform the analysis, were not valid reasons for failing to provide the requisite business cases. AUMA/EDM/CG argued that ATCO Pipelines was aware of the requirements for business cases from at least 2000, the date of the CWNG 1997 – 98 GRA decision. Further, they

were given ample opportunity during the hearing to provide more detailed business case analysis and further detail on the purpose of the proposed expenditures.

AUMA/EDM/CG submitted it was clear the larger project of Line Pack Management and Customer Account Balancing, including some TIS capital expenditures, was not allowed proper review by the customers.

AUMA/EDM/CG submitted that ATCO Pipelines did not provide sufficient evidence to justify the TIS capital expenditures of $4.6 million in 2003 and $860,000 in 2004, and these expenditures should be disallowed by the Board until such time as ATCO Pipelines provided properly prepared business cases supporting the project. AUMA/EDM/CG supported Calgary's recommendations requiring full and complete business case support for all future major capital projects greater than $300,000.

AUMA/EDM/CG submitted that to the extent possible, the allocation of IT operating expenses and capital projects should reflect usage. AUMA/EDM/CG did not support a simplistic allocation between North and South based only on revenues.

Calgary

Based on the filed evidence and cross-examination evidence, Calgary concluded the following with respect to the forecast 2003 and 2004 IT projects:

- ATCO Pipelines $540,000 XP and $5,350,000 TIS projects were responsible for the large increase in the IT budget
- ATCO Pipelines did not have a formalized, written business case process
- ATCO Pipelines is not aware of or is not utilizing the I-Tek PMO office and its Statement of Work or Business Case delivery capability
- ATCO Pipelines has provided no evidence that the vendor no longer supports the Centura and PL/SQL programming language in which the TIS system is written[17].
- ATCO Pipelines over simplified and over exaggerated the statement:[18] "We're basically -- if you look at customer billing systems and what other utilities have expended, we're way off the chart in terms of not spending very much. We would be way in the low-end extreme." The TIS (billing) software development including balancing is forecast to cost[19] approximately $20,000 per customer whereas the purchase of CIS (billing) software for a utility should cost[20] approximately $3 per customer. It would appear that ATCO Pipelines simply compared the dollar costs to ATCO Gas and ATCO Electric, and not the cost per customer, which is the more normal way to examine utility billing systems.
- ATCO Pipelines has not treated the large capital costs of the XP and TIS projects as an independent company, but seems to have trusted ATCO I-Tek to proceed based on no formal evaluation of the projects.

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17 CAL.AP-133(c)

18 Tr. p. 404, lines 12 – 16

19 $5,350,000/(210 – 270 customers)= $20,000 - $25,000 or approximately $20,000

20 Decision 2002-069, ATCO Affiliate Part A, Section 5.2.1 Position of the Parties, last paragraph on page 69 (In Reply Argument, Calgary noted that Mr. Galluzzi's [ATCO's expert] report suggested that commercially available CIS software for utility in the range of 0.75 to 1.5 million customers would be about $3 per customer.)

For IT Projects, Calgary recommended that the Board order ATCO Pipelines, for all future IT application or technology projects over $300,000, to provide “complete project business cases” and to specify in what accounts business benefits will accrue. In addition, Calgary recommended that the Board disallow the TIS Project until ATCO Pipelines provided a “complete project business case” that could be examined by interested parties and satisfied the Board of the merits of the project.

For IT Volumes, Calgary recommended that the Board order ATCO Pipelines in all future GRA applications to provide a table of I-Tek volumes in the same manner as contracted from its I-Tek affiliate showing both operating and project development volumes for the 3 years prior to and the forecast years of the GRA. Calgary also submitted that an explanation of any forecast variance over 10 % should reference the computing application or technology causing the variance.

For IT North/South Allocation (see IT Operating section for details), Calgary recommended that the Board order ATCO Pipelines to modify the Shared Services Policy and create a new allocation method to reflect the relative transportation revenues of North and South (approximately 67% to the North and 33% to the South). This new “Transportation Revenue” allocation method should be used for both IT operating expenses and IT capital project costs so that the APS and APN IT budgets, as a %age of the respective APS and APN transportation revenues, are approximately the same.

Calgary submitted that the additional information in IR responses added little to an understanding of why ATCO Pipelines was requesting 2003 and 2004 approval for $6 million for the XP and TIS projects. Calgary argued that the bits and pieces from the filing and the various IR responses did not constitute a proper business case.

Calgary noted that ATCO Pipelines attempted to do in argument what it failed to do in its filing - document its justification for these two projects:

- XP Project Justification – “The current Windows NT infrastructure is no longer supported by the vendor”, and must be replaced.
- TIS Project Justification – “Centura is an outdated programming language, need to utilize current technology in order to be able to continue operating. Current hardware and software tools are outdated and need to be brought up to current technology.”

When requested to explain when and why ATCO Pipelines considered Centura an outdated programming language, ATCO Pipelines stated:[21]

> Over the past couple of years it has become more and more difficult to get Centura programmers. ATCO Pipelines does not have any in house programmers, so we rely on I-Tek to provide this service.”

Calgary submitted that the Board should not accept as the primary justification the replacement of aging technologies, when ATCO Pipelines has chosen to rely on a single affiliate supplier which has decided not to maintain the staff capabilities to service the systems. Calgary submitted that no competitive corporation, particularly one that alleges that it is facing increasingly competitive pressures, would act in such a manner.

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[21] CG-ATCO Pipelines-34(b)

In addition, Calgary submitted that the absence of an ATCO Pipelines formalized business case process was contributing to a rapidly rising ATCO Pipelines IT budget (operating expenses plus hardware depreciation plus software amortization) and that the TIS project was the major contributor to this rapidly rising IT budget. Therefore, Calgary submitted that the project should not be approved.

Views of the Board

The Board notes that ATCO Pipelines argued that the XP Project complied with the Board's directions in Decision 2001-97. Based on the evidence, a business case was prepared for the ATCO Group for the XP project in consultation with the affected companies, including ATCO Pipelines. The Board further notes that ATCO Pipelines argued that it was clear that software packages no longer supported by the vendor must be replaced in order for business operations to continue.

The Board notes that ATCO Pipelines submitted that it would be inefficient to require a listing of each and every alternative, such as converting to manual systems, using adding machines, paying a fee for service to support broadly used software, all of which could be quickly discounted by ATCO Pipelines. However, the Board is of the view that ATCO Pipelines' failed to provide any information on the alternative of continuing Windows NT on a fee for service basis or any other option.

The Board agrees with the submissions of interveners that ATCO Pipelines failed to provide an adequate level of detail via a business case incorporating the costs and benefits, and possible alternatives for the XP project, and that the cost/benefit analysis was conducted by ATCO I-Tek for the ATCO Group.[22] The Board also notes that the sponsor of the XP project had not seen the cost/benefit analysis on the XP project.[23] The Board considers that a cost/benefit analysis conducted at the corporate level and provided by an affiliate, where the Applicant has limited knowledge of the analysis, offers little comfort to the Board as to the reasonableness check of the XP project as it relates specifically to ATCO Pipelines. In addition, the Board considers that while ATCO Pipelines may be able to easily discount various options, it is the applicant's responsibility or burden of proof to justify capital projects to the satisfaction of the Board, and failure to substantiate these costs/benefits are at the applicant's risk.

Nevertheless with respect to the XP project, the Board considers that an upgrade is needed to meet ATCO Pipelines' business requirements. Therefore, the Board will allow the XP project, but based on the Applicant's failure to adequately justify the costs of the project, the allowed expenditures shall be reduced by 15%. The Board directs ATCO Pipelines to reflect, in its Refiling, the reduction of 15% to the capital expenditures for the XP project.

The Board supports the AUMA/EDM/CG submission that it would be beneficial to have information concerning the number of personal computers and servers being upgraded and the cost per unit. Information concerning software implementation and training costs would also be of assistance in reviewing projects of this nature. Therefore, the Board directs ATCO Pipelines, in future GRA's, to include this level of this detail in its business cases for IT projects of this nature.

22 Cross Examination of ATCO pipelines on XP Project, Response to undertaking Tr. p. 795, lines 8-15
23 Cross Examination, p. 190 lines1-25, and p. 396 lines 1-5

With regards to the TIS project, the Board notes that ATCO Pipelines submitted that it has presented a business case in respect of the TIS project that complies with the Board's directions in Decision 2001-97. The Board also notes that ATCO Pipelines argued that the business case for TIS is based on an existing key billing and customer information system, using an outdated programming language with which numerous problems and outages have been experienced. ATCO Pipelines indicated that it could not function without this situation being corrected. ATCO Pipelines argued that the benefits of the TIS were "blatantly obvious" in terms of the status of the existing ATCO Pipelines system and in terms of the remedy required to maintain a reliable and secure customer information and billing system.[24] Since the existing system was specifically built to handle ATCO Pipelines' unique data and measurement sources, it appears reasonable to the Board that it would not be the type of system for which a third party software package would be available to economically meet the business requirements.

However, the Board agrees with the submissions of interveners that ATCO Pipelines failed to adequately justify the costs of the TIS project via a business case or cost benefit analysis. ATCO Pipelines' statement in cross-examination that benefits of the project are " blatantly obvious", does not justify the appropriateness of the project. However, the Board recognizes that Centura is an outdated programming language that requires an upgrade to hardware and software tools, and Centura programmers may be difficult to find. Therefore, the Board considers that while ATCO Pipelines failed to fully justify the costs of the project, it did show a need for the project. Therefore, the Board will allow the TIS project, but based on the Applicant's failure to adequately justify the costs of the project, the allowed expenditures shall be reduced by 15%.

The Board also considers, and directs, that for all future IT application or technology projects over $500,000, ATCO Pipelines should provide, within the IT project business cases, the impact on I-Tek volumes in the same manner as contracted from its I-Tek affiliate (e.g. mainframe services, distributed services, network services, workstation services, and application services).

The Board is of the view that a cost threshold for business cases offers only a guideline and does not negate or reduce the Applicant's responsibility to justify all of its capital expenditures.

The Board also notes that Calgary submitted argument on the shared services allocation for IT projects. The Board considers that shared services allocation issues are better addressed in ATCO Pipelines' 2003/2004 Phase II Proceeding.

2.2.5 Replacements

2.2.5.1 Transmission Replacements-General, North

Expenditures of $1,866,000 and $1,658,000 were forecast for 2003 and 2004, respectively for replacement of transmission facilities including river crossings, replacement of cathodic protection equipment, and replacement of obsolete equipment at meter stations. Pipeline lowering and relocations were forecast in the amounts of $1,000,000 for each of 2003 and 2004, with offsetting contributions of $600,000 for each of 2003 and 2004.

[24] Cross-Examination of the ATCO Pipelines Panel by Board Counsel, Tr., p. 875, lines 18-25

Views of the Applicant

ATCO Pipelines noted that no intervener opposed the amounts requested by ATCO Pipelines with respect to APN Replacement Related Expenditures. ATCO Pipelines argued that it provided the necessary information to alleviate any misconceptions of "double counting" as suggested by the AUMA/EDM/CG and that sufficiently detailed descriptions were provided by ATCO Pipelines to demonstrate that there was no duplication of costs between general and specific projects.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG submitted that the following table was a historical summary of APN's forecast and actual Transmission Replacement–General expenditures for the years 1999 to 2004.

Table 8. APN Historical/Forecast Replacement – General Capital Expenditures ($000)

99 A	00 F	00 A	01 F	01 A	02 F	02 A	03 F	04 F
1,444	N/A	2,338	N/A	2,107	2,323	2,342	1,866	1,658

AUMA/EDM/CG did not object to the amounts requested by APN for Replacement–General capital expenditures, but submitted that the Board should direct APN to be clearer in their descriptions and breakout of costs for this category in its next GRA to ensure there was no duplication of costs between general and specific projects.

Views of the Board

The Board considers that the forecast amounts for Transmission Replacement-General for APN are reasonable. In the future, the Board expects ATCO Pipelines to alleviate the concerns of interveners regarding double counting by providing greater clarity in expenditure descriptions and breakdowns of costs in the original application. The Board accepts the forecasts as filed.

2.2.5.2 2003 Transmission Replacements – Specific North

Athabasca River Pipeline Crossing Replacement

Views of the Applicant

ATCO Pipelines proposed the replacement of the transmission line crossing the Athabasca River in the amount of $1,500,000 in 2003. ATCO Pipelines argued that the Athabasca River crossing must be replaced as the current crossing was exposed and prone to damage and/or failure. ATCO Pipelines submitted that there were five receipt stations which produced approximately 35 TJ/day located upstream of the river crossing. ATCO Pipelines argued that an unplanned failure of the crossing would require the curtailment of these volumes. Also, up to 47 TJ/day of natural gas requirements for the City of Edmonton were supplied from an interconnection with NGTL, located upstream of the crossing. ATCO Pipelines argued that if a failure occurred in late spring, the probability existed that this volume would not be available for the next heating season. As no other unutilized crossings existed in the area, ATCO Pipelines submitted that the only plausible solution was replacement to ensure the long-term integrity of the pipeline network.

In Reply Argument, ATCO Pipelines noted that AUMA/EDM/CG suggested that ATCO Pipelines failed to provide a business case for the project. ATCO Pipelines argued that it provided a business case for this project in accordance with Board requirements that included:

- Detailed Justification including Demand Energy and Supply Information
- Breakdown of the Project Cost
- Options and their Economics

AUMA/EDM/CG

AUMA/EDM/CG noted that ATCO Pipelines failed to provide a business case for the project, including a description of reasonable alternatives such as reburial or armoring. However, considering ATCO Pipelines' statement that additional exposure was seen in 2002, AUMA/EDM/CG did not object to this proposed addition to rate base.

Views of the Board

The Board agrees with AUMA/EDM/CG that ATCO Pipelines failed to provide a satisfactory business case addressing costs, benefits and alternatives. However, the Board is of the view that concerns about potential damage or failure at exposed river crossings are paramount and in this case outweigh ATCO Pipelines' failure to provide detailed justification. Therefore, the Board approves the forecast expenditures for this project as filed.

2.2.5.3 Transmission Replacements-General South

Replacements of transmission facilities – general South were forecast in the amounts of $1,675,000 and $1,595,000 for 2003 and 2004, respectively. This includes replacement of pipeline at river crossings, replacement of cathodic protection equipment, replacement of obsolete equipment at meter stations and pipeline lowering and relocates. The pipeline lowering and relocates were forecast to be $1,000,000 for each of 2003 and 2004, with offsetting contributions of $600,000 for each of 2003 and 2004.

Views of the Applicant

ATCO Pipelines noted that the AUMA/EDM/CG recommend disallowances of 44% and 41% for 2003 and 2004 respectively for APS Replacement Related Expenditures. ATCO Pipelines submitted that there was no rational basis for such disallowances. As noted in the Application, the forecast general replacement expenditures were $1,675,000 and $1,595,000 for 2003 and 2004 respectively.

The methodology for forecasting replacement expenditures for APS used historical expenditure levels tempered with judgment. ATCO Pipelines submitted that the historical costs were as follows:

Table 9. APS Historical Replacement General Expenditure ($000)

	1999 Actual	2000 Actual	2001 Actual	2002 Forecast
General	1108	1825	1645	1089
1999-2001 Average			1526	
1999-2002 Average				1417

ATCO Pipelines noted that the forecast expenditures were marginally greater than the 1999-2001 average, reflecting the forecast requirements for overall replacements of ATCO Pipelines' South system. ATCO Pipelines noted that AUMA/EDM/CG and Calgary suggested that the forecast for 2003 and 2004 appeared to be too high and perceived "double counting" for water crossings and pipeline replacements. ATCO Pipelines argued that no "double counting" had occurred. ATCO Pipelines submitted that the forecast expenditures were appropriate and requested approval as filed.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG submitted that the following table shows a historical summary of APS' forecast and actual Transmission Replacement – General expenditures for the years 1999 through 2004, inclusive. AUMA/EDM/CG showed the 2000, 2001 and 2002 forecast from the 2001/02 APS GRA and the current 2003/04 ATCO Pipelines GRA. For 2002, numbers from both GRAs were used.

Table 10. APS Historical/Forecast Replacement – General Capital Expenditures ($000)

99 A	00 F	00 A	01 F	01 A	02 F	02 F	02 A	03 F	04 F
1,108	2,101	1,825	2,585	1,645	2,390	1,089	941	1,675	1,595

Using the table above, AUMA/EDM/CG argued that it showed APS had consistently over-forecast compared to actual for the years 2000, 2001 and 2002, including the 2002 forecast approved in the 2001/02 GRA and as shown in the 2003/04 GRA. The amount of over-forecasting compared to actual was 13% for 2000, 36% for 2001, 61% for 2002 (01/02 GRA) and 14% for 2002 (03/04 GRA). This over-forecasting had been consistent and appeared to increase (using 2002 as the example), the further out the forecast was projected.

AUMA/EDM/CG submitted that the Board should approve Replacement–General capital expenditures for APS in the same amounts as the 2002 actuals of $941,000. AUMA/EDM/CG submitted that these amounts are $734,000 and $654,000 less than the forecasts submitted by ATCO Pipelines for 2003 and 2004, respectively. AUMA/EDM/CG also submitted that the Board should direct ATCO Pipelines to be clearer in their descriptions and breakout of costs for this category in its next GRA to ensure there is no duplication of costs between general and specific projects.

Calgary

Calgary submitted that the 2002 actuals were only about 55% of the last GRA forecast for these expenditures. Further Calgary argued that there seems to be some "double counting" in that the "general" expenditures are unsupported and there are two estimates for water crossings and pipeline replacements that are also unsupported and for which no amounts were expended in the past two years. Calgary recommended that the APS replacement related expenditures be approved at approximately 10% higher than the average for the 2001 and 2002 actuals.

Views of the Board

The Board notes that Table 10 above dealing with APS Historical/Forecast Replacement – General Capital Expenditures shows a history of over-forecasting in this category that increases the further out the forecast is projected. The Board considers that a reduction of 15% should be

applied to ATCO Pipelines' Forecast Replacement – General Capital Expenditures for the South, in recognition of the consistent record of over-forecasting for APS. The Board also notes that this reduction is consistent with the downward trend for actual expenditures in this category.

The Board directs ATCO Pipelines, in the Refiling, to reduce its forecast of Replacement General South by 15% in each test year.

2.2.5.4 Transmission Replacements – Specific South

Turner Valley Transmission Replacement

Views of the Applicant

ATCO Pipelines proposed to replace the Turner Valley transmission line 2003 estimated in the amount of $500,000. ATCO Pipelines stated that there are integrity issues associated with the Turner Valley Transmission pipeline that necessitate the replacement of the pipeline and that replacement was the only suitable alternative, as no other source of supply was available to serve the community. The project involves replacement of 3 km of 168 mm pipeline at a forecast cost of $500,000. ATCO Pipelines argued that it had met the Board's requirements for business cases as outlined in Decision 2001-97.

Views of the Interveners

AUMA/EDM/CG

Although there was no business case to support this project, given the age of the assets and condition of the pipe, AUMA/EDM/CG did not oppose this project.

Views of the Board

The Board accepts ATCO Pipelines' Turner Valley Transmission Replacement project as a reasonable expenditure considering that the current pipeline was installed in 1922, and that replacement is required to ensure safe and reliable supply.

2.2.6 Specific Projects – North and South

2.2.6.1 Watercourse Crossings

Other Watercourse Crossing Replacements – APN

ATCO Pipelines proposed other various water course crossings required replacements in 2004 in the amounts of $1,500,000 for APN and $1,000,000 for APS. ATCO Pipelines argued that at the time of the Application, various crossings were under review for replacement in 2004. Reports were due from ATCO Pipelines' consultant in the spring of 2003 with respect to various crossings and their status. ATCO Pipelines submitted that the Athabasca River crossing on the Jasper Transmission system was the river crossing that was identified for replacement in 2003 subject to the final consultant's report. The other crossings identified in the Application are being reviewed for replacement in the future. ATCO Pipelines argued that only replacement of the crossing would provide a long-term solution to the integrity of this crossing.

ATCO Pipelines noted that AUMA/EDM/CG suggested that this category could be "misused to hide large capital projects". ATCO Pipelines urged that such an unfounded allegation be given no consideration by the Board. ATCO Pipelines indicated that it identified in its Application the watercourse crossing expenditure as a major capital expenditure. All relevant data was available

to the AUMA/EDM/CG to cross-examine ATCO Pipelines' witness on this subject matter. The AUMA/EDM/CG chose not to do so. There was no basis for AUMA/EDM/CG to state that evidence was not available. ATCO Pipelines also requested that the Board disregard AUMA/EDM/CG's suggestion for the establishment of a $300,000 threshold for major capital projects, as there was no justification on the record to support this recommendation.

Watercourse Crossing Replacements – APS

ATCO Pipelines argued that the Chin Lake crossing must be replaced in 2004, due to decreases in available supply should the crossing fail prior to the 2004/2005 heating season. Consultant reports outlined that this pipeline is exposed for the majority of the crossing and is susceptible to mechanical failure in the banks due to human activities (i.e. quads, etc.). ATCO Pipelines argued that due to the significant exposure of this pipeline and the impact of failure to downstream customers, this crossing must be replaced.

ATCO Pipelines noted AUMA/EDM/CG's statement that such major capital projects should be identified among the major capital expenditures. ATCO Pipelines submitted that it identified the Chin Lake crossing project in its Application as a major capital expenditure. Similar to the situation with APN, ATCO Pipelines requested that the Board dismiss the AUMA/EDM/CG's recommendation for a $300,000 threshold.

AUMA/EDM/CG

AUMA/EDM/CG stated that it was concerned general categories such as "Watercourse Crossings" for APN and APS may be misused to hide large capital projects in GRA type reviews. In this instance, both repairs are significant capital expenditures and should have been identified among the major capital expenditures for the 2004 test year. Further, AUMA/EDM/CG argued that major capital expenditures should be supported with cost benefit analyses and a business case. AUMA/EDM/CG recommended that the Board direct ATCO Pipelines to identify all capital expenditures greater than, or equal to, $300,000 as major capital expenditures and supply appropriate cost benefit analyses and business cases to support such expenditures. In the absence of such supporting information, AUMA/EDM/CG argued that the Board should not approve such projects or, at the least, take into account the shift in risk to customers when determining the rate of return.

Views of the Board

The Board has considered the positions of the parties and is satisfied that ATCO Pipelines has identified the major projects in this category. The Board does not agree with AUMA/EDM/CG that $300,000 in capital expenditures should be the threshold for a required a business case analysis. The Board considers ATCO Pipelines' $500,000 internal benchmark to be appropriate. However, the Board is of the view that a cost threshold for business cases offers only a guideline and does not negate or reduce the Applicant's responsibility to justify all of its capital expenditures. Based on the evidence provided in the proceeding, the Board accepts the Watercourse Crossing Replacements as filed.

2.2.6.2 Pipeline Replacement

Views of the Applicant

ATCO Pipelines proposed other transmission line replacements in 2004 in the amounts of $1,500,000 for APN and $1,000,000 for APS. ATCO Pipelines argued that it identified the Grande Cache pipeline expenditure in its Application as a major capital item. The Grande Cache pipeline was noted in the Application and further explained in the response to BR.AP-25(e), including an engineering assessment. The information provided covered the areas of need, justification, alternatives and costs. ATCO Pipelines submitted that all relevant data was available to the AUMA/EDM/CG to cross-examine ATCO Pipelines' witness on this subject and to later state that evidence was not available was unfounded and must be dismissed by the Board. ATCO Pipelines also requested that the Board disregard AUMA/EDM/CG's attempt to establish a $300,000 threshold for major capital projects, because at no time did this intervener submit any evidence on this issue or provide any rationale for the amount.

ATCO Pipelines noted that AUMA/EDM/CG suggested that this category could be "misused to hide large capital projects". With respect, ATCO Pipelines submitted that this allegation was completely unfounded and was not supported by any evidence. ATCO Pipelines urged the Board to give no consideration to such an unfounded allegation.

ATCO Pipelines noted that AUMA/EDM/CG submitted that such major capital projects should be identified among the major capital expenditures. ATCO Pipelines identified in the Application the Turner Valley #2 pipeline expenditures as a major capital item. ATCO Pipelines argued that the Turner Valley #2 pipeline was noted in the Application and further explained in the response to BR.AP-29(d), including a leak history and depth of cover survey. The information provided covered the areas of need, justification, alternatives and costs as required by the Board.

Views of the Interveners

AUMA/EDM/CG

As with the Water Crossing General forecast, AUMA/EDM/CG indicated that it was concerned general categories, such as "Pipeline Replacement" for APN and APS may be misused to hide large capital projects in GRA type reviews. Consequently, AUMA/EDM/CG reiterated their recommendation that the Board direct ATCO Pipelines to identify all capital expenditures greater than, or equal to, $300,000 as major capital expenditures and supply appropriate cost benefit analyses and business cases to support such expenditures. In the absence of such supporting information, AUMA/EDM/CG suggested that the Board should not approve such projects or, at the least, penalize the Applicant by reducing the amount requested.

Views of the Board

The Board is not convinced by AUMA/EDM/CG's assertion in this instance that this category could be misused to hide large capital projects. The Board is of the view that ATCO Pipelines adequately identified and justified the major capital expenditures in the Pipeline Replacement category. Therefore, the Board accepts the Pipeline Replacement expenditures as filed.

2.2.6.3 Land and Structures (Combined Growth/Improvement/ Replacement)

Views of the Applicant

ATCO Pipelines proposed expenditures for land and structures in 2003 in the amounts of $208,000 for APN and $128,000 for APS and in 2004 in the amounts of $115,000 for APN and $65,000 for APS. ATCO Pipelines noted that AUMA/EDM/CG prepared a table outlining historical and forecast capital expenditures. Although the table referenced CAPP.AP-4 as the source of the information, the AUMA/EDM/CG table incorrectly indicated that there were no expenditures for each of 1999 and 2000. ATCO Pipelines submitted that a review of the table provided by ATCO Pipelines in response to CAPP.AP-4 clearly showed expenditures for Land and Structures for APN for both 1999 and 2000.

ATCO Pipelines noted that AUMA/EDM/CG recommended disallowances of 76% and 57% in respect of the ATCO Pipelines forecasts for 2003 and 2004 respectively. AUMA/EDM/CG also stated that APN was in a negotiated settlement for the years proceeding the test years, and it could see no reason why capital spending in this area should be higher in the test years than in previous years.

ATCO Pipelines assumed that AUMA/EDM/CG made these statements based solely upon its own flawed analysis as demonstrated by its incorrect calculation of forecast expenses for 1999 and 2000. ATCO Pipelines argued that there was no basis in the evidence for the AUMA/EDM/CG statements and no justification for the recommended disallowances. ATCO Pipelines submitted that the forecast APN expenditures of $208,000 and $115,000 for 2003 and 2004 respectively were necessary for ATCO Pipelines' continued operations and were appropriate. ATCO Pipelines requested their approval by the Board.

With regards to APS, ATCO Pipelines noted that no intervener recommended any reductions to the APS forecast expenditures. However, similar to the Land and Structures expenditures for APN, ATCO Pipelines noted that AUMA/EDM/CG had completed an incorrect analysis for APS using the available data from IR response CAPP.AP-4. ATCO Pipelines noted with interest that for APN, AUMA/EDM/CG had recommended that the four-year average (1999-2002) be used for the test period, yet in the case of APS, AUMA/EDM/CG agreed with ATCO Pipelines' forecast. ATCO Pipelines argued that if AUMA/EDM/CG were consistent in their approach to forecasting, ATCO Pipelines would assume that they should recommend an increase for 2004.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG noted that the average of 1999 through 2002 is $50,000 per year for total land and structures capital expenditures. AUMA/EDM/CG considered that the 2003 and 2004 forecasts should be at a level equal to the previous four years. Therefore, AUMA/EDM/CG recommended that the 2003 and 2004 forecast for Land and Structures should be restricted to $50,000 per year, the average for the period 1999-2002, inclusive.

AUMA/EDM/CG noted that APS's average actual expenditures for the period 1999 through 2002 were $116,000 per year for land and structures. Consequently, AUMA/EDM/CG considered the APS forecast, averaged over the two test years, within reason.

Views of the Board

The Board considers the APS forecast to be within reason based on historical expenditures. The Board notes AUMA/EDM/CG's submission that APN was in a negotiated settlement for the years preceding the test years, and that AUMA/EDM/CG saw no reason why capital spending in this area should be higher in the test years than in previous years. The Board considers an adjustment to the negotiated settlement levels would fail to take into consideration the possibility that expenditures under this category may have been part of the give and take in reaching the previous settlement. As such, the Board considers that any adjustment would be strictly arbitrary.

The Board therefore considers the forecast expenditures for land and structures for both APS and APN is reasonable. However, the Board notes that it applied an adjustment to ATCO Pipelines forecast of Full Time Equivalents (FTEs) in the Operation and Maintenance section of this Decision. Therefore, the Board directs ATCO Pipelines to reflect the impact of the aforementioned adjustment on any affected land and structures expenditures in its compliance filing, including any supporting rationale in this category.

2.2.6.4 Moveable Equipment (Combined Growth/Improvement/Replacement)

Views of the Applicant

ATCO Pipelines forecast expenditures for moveable equipment in 2003 in the amounts of $1,502,000 for APN and $421,000 for APS and in 2004, in the amount of $1,107,000 for APN. ATCO Pipelines noted that the AUMA/EDM/CG suggested, based on ATCO Pipelines' response to CG.AP-39, that replacement of vehicles should occur at a uniform rate with no more than 20% of vehicles being replaced each year, or on a one in five year basis. ATCO Pipelines argued that this misguided suggestion would require ATCO Pipelines to arbitrarily replace vehicles every five years, regardless of usage or condition. ATCO Pipelines argued that this would result in an imprudent expenditure of funds if a vehicle had not reached its useful life, and could provide a safety hazard to ATCO Pipelines' employees if the vehicle in question was well past its useful life. ATCO Pipelines submitted that the correct methodology is to replace vehicles as they end their useful life. Although the "average" life is about four to five years, as indicated by ATCO Pipelines in CG.AP-39, the end of a vehicle's useful life can occur before or after the four to five year "average" life of the vehicles.

ATCO Pipelines noted that AUMA/EDM/CG referenced to the total vehicle replacement costs of $1,215,000 and $957,000. However, these costs include non-vehicle related costs. The response to BR.AP-25(f) clearly shows the vehicle replacement costs to be $605,000 and $490,000 for 2003 and 2004 respectively as follows:

Table 11. APN Breakdown of Vehicle Replacement Costs ($000's)

	2003 Forecast	2004 Forecast
Transportation Equipment Purchases	605	490
Tool & Work Equipment Purchases	60	70
Heavy Equipment	310	130
Office Equipment	46	33
Communication Equipment	194	234
Total	**1215**	**957**

ATCO Pipelines noted that AUMA/EDM/CG also suggested that the replacement of other equipment should occur at a uniform rate. ATCO Pipelines argued that this was completely unfounded and without merit.

ATCO Pipelines noted that AUMA/EDM/CG questioned and based their recommendation for ATCO Pipelines' 2003 and 2004 forecasts on the variance between the ATCO Pipelines 2002 Forecast and Actual. ATCO Pipelines' explanation for the difference was outlined in AUMA/EDM.AP-48(a). As noted, ATCO Pipelines argued that the primary reasons were lower than expected auxiliary and equipment costs for vehicles and lower than anticipated completion of communication related projects. The completion of this communication work must now be done in 2003.

ATCO Pipelines submitted that the Argument provided by AUMA/EDM/CG was inappropriate and imprudent and that there was no basis for the 46% and 26% disallowances being recommended for 2003 and 2004 respectively. ATCO Pipelines argued that the recommendations of AUMA/EDM/CG should be dismissed by the Board and the ATCO Pipelines forecast approved as filed.

Similar to the arguments relating to APN, ATCO Pipelines argued that AUMA/EDM/CG imprudently relied upon a one in five year replacement for vehicles and other components of moveable equipment as a basis for their recommended decrease for APS forecasts. ATCO Pipelines noted that AUMA/EDM/CG recommended that the forecast for movable equipment should be set at the average for the period 1999-2002, namely $387,500 for each of the test years. ATCO Pipelines submitted that the recommendations of the AUMA/EDM/CG were inappropriate and imprudent, and should be dismissed by the Board.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG noted that the average annual expenditure from 1999 through 2002 was $815,000 for total moveable equipment capital expenditures. AUMA/EDM/CG considered that APN's 2003 and 2004 forecasts should be set at a level equal to the previous four years. As with Land and Structures, AUMA/EDM/CG noted APN was in a negotiated settlement in the years proceeding the test years. There appeared to be no reason why capital spending in this area should be higher in the test years than in previous years. AUMA/EDM/CG also noted that ATCO Pipelines had over forecast moveable equipment replacements by 33% for 2002 as compared with 2002 actuals. Therefore, AUMA/EDM/CG recommended the 2003 and 2004 forecasts be reduced to the average for 1999-2002, namely $815,000 per year.

AUMA/EDM/CG also noted that ATCO Pipelines indicated average vehicle life required replacement of 20% of the vehicles each year. AUMA/EDM/CG considered that this should allow for reasonably equivalent replacement expenditures each year. However, AUMA/EDM/CG noted a 2000 actual as low as $424,000 while test years are forecast at $1,215,000 for 2003 and $957,000 for 2004. AUMA/EDM/CG considered this forecast was unreasonable and expected that replacement of vehicles and other equipment should occur at a uniform rate, with no more than 20% of vehicles being replaced each year.

With regards to APS, AUMA/EDM/CG noted that actual expenditures for 1999 through 2002 were $1,550,000 for moveable equipment capital expenditures. This compared with $1,350,000

for the combined three year total from the 2002 estimate through to the 2004 forecast. AUMA/EDM/CG submitted that it saw no reason why current year expenditures were so much higher than 1999 though 2001 expenditures. Therefore, AUMA/EDM/CG recommended that the forecast for movable equipment should be set at the average for the period 1999-2002, namely $387,500 for each of the test years.

AUMA/EDM/CG also noted in relation to APS that ATCO Pipelines indicated that the average vehicle life required replacement of 20% of the vehicles each year. AUMA/EDM/CG considered that this should allow for reasonably equivalent replacement expenditures each year. However, AUMA/EDM/CG indicated that the 2000 actual was as low as $0 while the test years are forecast by ATCO Pipelines at $240,000 for 2003 and $345,000 for 2004. AUMA/EDM/CG considered this was unreasonable and expected replacement of vehicles and other equipment should occur at a uniform rate with no more than 20% of vehicles being replaced each year.

Views of the Board

The Board notes the concerns of AUMA/EDM/CG that, for both APS and APN, moveable equipment expenditures should be replaced at uniform rate. However, the Board agrees with ATCO Pipelines' submission that the correct methodology is to replace vehicles as they end their useful life. The Board is of view that AUMA/EDM/CG's argument that moveable equipment expenditures for APN should remain the same as under the four year settlement, fails to take into consideration the give and take in the negotiated settlement process, and the useful life of the asset. Therefore, the Board accepts as reasonable ATCO's forecasts for 2003 and 2004 as filed. However, the Board notes that it applied an adjustment to ATCO Pipelines forecast of Full Time Equivalents (FTEs) in the Operation and Maintenance section of this decision. Therefore, the Board directs ATCO Pipelines to reflect the impact of the aforementioned adjustment on the moveable equipment expenditures in its compliance filing, including any supporting rationale in this category.

2.2.7 Customer Contributions

Customer contributions may be required from Industrial/Producer customers or from individuals or organizations requesting pipeline lowerings or relocates.

For industrial/producer customers, ATCO Pipelines submitted that a contribution was only required if the present value of their minimum contract term charges were less than the investment required for facilities to provide service to them. For the test period, industrial/producer contributions were forecast to be zero as customers were forecast to contract for sufficient term.

For individuals/organizations who may request lowerings/relocates, ATCO Pipelines indicated in an undertaking to AUMA/EDM/CG counsel that it reviews the three year history and tempers the three year average on a look-forward basis with judgment on any requests that may be seen coming in the future. The following three-year historical contributions were provided:

Table 12. APS/APN Historical Contributions ($000)

	North	South
2000Actual	905	862
2001 Actual	591	321
2002 Forecast	415	456
Average	637	546

The forecast contributions for both APN and APS were $600,000 for both 2003 and 2004. ATCO Pipelines argued that this was consistent with the three-year average expenditures and projects foreseen in the capital program.

The forecast capital expenditure for Pipeline Customer Requests was $600,000 for both APN and APS for 2003 and 2004. ATCO Pipelines argued that this meant that the forecast contributions offset the forecast capital expenditures each year, which resulted in a zero impact to rate base. Accordingly, ATCO Pipelines requested the Board to approve the contributions as forecast.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG were satisfied that the method to forecast customer contributions for line moves was reasonable, providing ATCO Pipelines exercised some judgment with respect to adjustments, either upwards or downwards, to the forecast to account for expected events in the test years that did not occur in the historical years.

AUMA/EDM/CG recommended that for the Jasper NOP Upgrade – Peers to Marlborough that the Board direct ATCO Pipelines to include an additional deemed producer transportation customer contribution in the amount of $2.407 million.

Views of the Board

Based on the three-year average expenditures experienced by ATCO Pipelines and projects foreseen by the Applicant in the capital programs, the Board accepts as reasonable the forecast customer contributions for pipeline lowerings/relocates of $600,000 for APS and APN for both 2003 and 2004. The Board notes that the issue of a deemed contribution for the Jasper NOP Upgrade-Peers to Marlborough has been address previously in Section 2.2.3.2 of the Decision.

2.2.8 Summary of Board Adjustments and Approved Capital Additions

The following table sets out the Board adjustments described in this Section of the Decision to the capital additions forecast by ATCO for the test years.

Table 13. Adjustments to Forecast Capital Additions ($000)

	2003	2004
Capital Additions Forecast	41913	29403
Reductions		
APN Transmission Growth General	780	560
Bretona Lateral Loop (APN Growth)		625
APS Transmission Growth General	210	197
Airdrie Heartland Lateral	124	
Transmission Improvement General –APS –	347	588
Line Pack Management (ATCO Pipelines Total)	1405	
Customer Account Balancing (ATCO Pipelines Total)	2700	2200
Information Systems- XP &TIS	750	150
APS Transmission Replacement	251	239
Total Reductions	6,567	4560
Approved Capital Additions	35,346	24,844

2.3 Necessary Working Capital (NWC)

Necessary working capital is added to rate base to compensate the utility for capital required in the day-to-day operations of the utility recognizing that a net lag exists between monthly cash flows when expenses are paid and when the revenue is received in cash for the provision of service.

2.3.1 Necessary Working Capital Items

Necessary working capital includes amounts for the following:

- Cash expenses
- Financial items
- Materials and supplies
- Deferred pension
- Reserve for injuries and damages
- Computer reserve deficiency
- Deferred income tax
- Hearing cost reserve
- Line pack

2.3.2 Lead-Lag Study Methodology and NWC Forecasts

Views of the Applicant

ATCO Pipelines forecast the total NWC in the amounts of $247,000 and $5,995,000 for 2003 and 2004 respectively. For APN, the NWC requirement was forecast in the amounts of $558,000 and $3,509,000 for 2003 and 2004 respectively. For APS, the NWC requirement was forecast in the amounts of $311,000 and $2,486,000 for 2003 and 2004 respectively.

The determination of cash expenses and financial items was supported by a lead-lag study. The lead-lag study utilized the 2001 payment and receipt patterns to determine revenue and expense lags and, except for lag days applicable to ATCO Gas and Affiliated Companies, was based on

the methodology approved in Decision 2001-97 for APS. A single average revenue lag, stated in days, was calculated by reviewing the time lag between the point of service and the receipt of payment for the service. Payment lags were calculated for each category of expense incurred in providing the service. The net lag days for each expense category were the result of the difference between the average revenue lag and the appropriate expense payment lag. Finally, the net lags were stated as a %age of 365 days and applied to forecast year expenses by category.

Revenue Lag
The revenue lag for APN was determined to be 37.08 days and for APS was 30.87 days.

Cash Expenses and Financial Items
The operating and maintenance expense lags were calculated as shown in the following table:

Table 14. Lead-Lag Study Results

	Expense Category	Percent Net Lag North	Percent Net Lag South
1	O&M Expenses	5.53	3.82
2	Gas Supply Costs	4.42	Not Applicable
3	Income Tax Installments	5.99	4.29
4	Income Tax Final Payment	-56.01	-57.71
5	Other Taxes	-0.34	-7.04
6	Debt Interest	-14.84	-16.54
7	Preferred Dividends	-2.34	-4.04
8	Common Dividends	-2.34	-4.04
9	Common Return	10.16	8.46
10	Depreciation Expense	10.16	8.46

ATCO Pipelines noted that AUMA/EDM/CG recommended that incentive payments be included in the payroll and payroll related expense component of the O&M expense lag. ATCO Pipelines noted that the difference in O&M expense lag %age rounds to zero, and as such, AUMA/EDM/CG's recommendation is immaterial and should be given no weight.

ATCO Pipelines requested approval for a 5.75 day lag with respect to affiliate lags, which reflected actual payment terms. ATCO Pipelines submitted that where payment terms were properly reflected in rates, there should be no issue with the lag period or payment terms, as the payment term would compensate the payee company for any NWC. ATCO Pipelines requested that the Board reconsider its direction in Decision 2001-97 requiring that ATCO Pipelines recalculate its lead/lag study with the application of a zero lag to ATCO Pipelines transactions with ATCO Gas South. In that Decision, the Board stated that there was no reason for lag days for payments to affiliates. However, in this Application, ATCO Pipelines argued that lag days for both affiliates and non-affiliate transactions should reflect actual payment clearance dates. ATCO Pipelines requested that the applied for affiliate lags be approved as filed.

ATCO Pipelines noted that the AUMA/EDM/CG submitted that affiliate transactions should reflect arms length commercial terms or a suitable proxy thereof. AUMA/EDM/CG recommended changing the affiliate service lag from 20.96 days to 35.50 days. Two reasons for this recommendation were given. ATCO Pipelines noted that while acknowledging that for regulated affiliate transactions "there will be no net gain or loss", AUMA/EDM/CG noted that the customers served by each regulated utility were different. ATCO Pipelines pointed out that this was a rate design (Phase II) issue and there were efficiencies flowing from concurrent payment.

Second, ATCO Pipelines noted AUMA/EDM/CG's observation that 25% ($1,511,000) of affiliate services (5% of the $31,266,000 total O&M shown on Table 2.4-5 of the Application) were provided by non-regulated affiliate services, and clearing these transactions at other than commercial terms might impact the affiliated group as a whole. ATCO Pipelines submitted that if AUMA/EDM/CG believed that "no net gain or loss for the affiliate group as a whole" was a desirable outcome for non-regulated affiliate lead/lag transactions, then AUMA/EDM/CG should also have recommended adjustment of the ATCO I-Tek lag of $2,206,000 (7% of the total O&M shown in Table 2.4-5 of the Application) from 53.21 days to 35.50 days. ATCO Pipelines argued that AUMA/EDM/CG's recommendation was one sided and unfair, and should be given no weight.

ATCO Pipelines requested that revenue and expense transactions should be treated consistently between ATCO Gas and ATCO Pipelines to reflect the affiliate clearance date of 5.75 lag days (fourth working day). This was based on a practice established by Canadian Utilities Limited requiring that for efficiency and consistency, all companies and groups settle inter-company accounts on the fourth working day.

Materials and Supplies
The NWC for materials and supplies inventory was determined by forecasting an O&M and Capital %age allocation, and then applying the O&M allocation (25%) against mid-year materials and supplies.

Deferred Pension
The NWC requirement for Deferred Pension was the forecast mid-year balance.

Reserve for Injuries and Damages
The NWC requirement for Reserve for Injuries and Damages was the forecast mid-year balance.

Computer Reserve Deficiency Account
ATCO Pipelines included a NWC requirement to recognize the mid-year effect of the Board approved unamortized costs related to the disposition of computer equipment to ATCO I-Tek, which were being amortized over five years commencing in 1999.

Deferred Income Tax
ATCO Pipelines reduced its NWC requirement to recognize the mid-year balances in the Deferred Income Tax account.

Hearing Cost Reserve
ATCO Pipelines adjusted its NWC requirement to account for the balance in the Hearing Cost Reserve account. The working capital requirement was calculated using the unamortized mid-year balance.

Line Pack
ATCO Pipelines included a NWC requirement for the Line Pack proposed to be purchased from ATCO Gas. The working capital requirement was calculated using a forecast of price times volume on a mid-year balance.

ATCO Pipelines argued that the inclusion of Line Pack in working capital was consistent with the Uniform Code of Accounts and past Board practice. ATCO Pipelines asserted that the Uniform Code of Accounts dealt with Line Pack as an inventory account and past Board practice was to treat the mid-year amount of inventory in working capital. The Line Pack was not being acquired in relation to new facilities. ATCO Pipelines argued that since Line Pack was being acquired as inventory, and as an investment, it needed to be included in working capital and an investment return earned thereon.

ATCO Pipelines argued that the NWC requirement of $3.505 million was related to the actual acquisition of system Line Pack (North and South combined) and was based on the $5.00/GJ AECO-C NIT price of gas, at the time of the Application. For new projects, ATCO Pipelines submitted that it would estimate and acquire incremental Line Pack requirements on a project-by-project basis.

ATCO Pipelines submitted that the FGA considered ATCO Pipelines' proposal with respect to Line Pack to be acceptable. ATCO Pipelines noted that Calgary, however, seemed to misunderstand the concept, as it stated "ATCO Pipelines acknowledged that it had notionally 'purchased' the Line Pack from the customer, AG and had made no provision to credit the customers from whom the gas was obtained." ATCO Pipelines stated that it intended to credit the customers from whom Line Pack had been obtained.

ATCO Pipelines noted Calgary's misunderstandings were highlighted by its argument that "shippers on the system should be totally responsible for supplying their own Line Pack", which ATCO Pipelines submitted was a new, untested proposal by Calgary.

ATCO Pipelines noted AUMA/EDM/CG's statement that ATCO Pipelines' "intent is to negotiate a price for Line Pack with customers and pay customers the value of it" and their further recommendation that Line Pack be excluded from rate base pending the establishment of a value and the negotiated transfer of that value to customers. ATCO Pipelines argued that these statements were incorrect. ATCO Pipelines established the price of $5.00/GJ ATCO-NIT price of gas for the purchase of the Line Pack based on its forecast. ATCO Pipelines submitted that in accordance with prospective ratemaking and the mid year convention, the forecast value for inclusion in rate base, based on $5.00/GJ ATCO-NIT price of gas and the forecast timing based on the mid-year convention, should be approved.

Views of Interveners

AUMA/EDM/CG

AUMA/EDM/CG noted that ATCO Pipelines included as part of the O&M expense lag an item related to payroll and payroll related costs. The expense lag of 10.45 days for payroll and payroll related costs forecast by ATCO Pipelines reflects the weighted average lags on salaries and wages, payroll deductions and benefits. The company acknowledged that the proposed 10.45 lag days does not include the lag related incentive payments. In Exhibit 29-18, the company provided a revised calculation of the payroll and payroll related expense lag incorporating the lag related to incentive payments. The revised calculation showed the payroll and payroll related items expense lag to be 13.89 days.

To the extent incentive payments were included as part of the forecast of salaries and wages it would be appropriate to reflect the corresponding lag in the lead lag study. Accordingly,

AUMA/CG recommended that ATCO Pipelines be directed to revise its O&M expense lag to incorporate the revised lag for payroll and payroll related expenses and reflect the change in its working capital calculation.

AUMA/EDM/CG noted in that Decision 2001-97, the Board stated:

> The Board notes the different treatment between payments to affiliates and other payments in the lead/lag study. Specifically, ATCO's proposed expense lag for affiliate payments (excluding I-Tek) is 20.96 days, as opposed to 34.16 days for other O&M expenses. The Board also notes that the expense lag for payments for I-Tek services is 53.21 days. The Board considers that, for the purpose of calculating NWC requirement, there is no reason why the lag days for payments to affiliates should be any less than the lag relating to arms length transactions. Accordingly, the Board directs ATCO to recalculate NWC balance using an expense lag of 34.16 days for payments for affiliate services (excluding I-Tek). [p. 29]

AUMA/EDM/CG noted ATCO Pipelines' statement that lag days for both affiliates and non-affiliate transactions should reflect actual clearance dates. AUMA/EDM/CG argued that the leads and lags for affiliate transactions should reflect the commercial reality of what they would be if the same services were provided by an arms length entity. Alternatively, the Company should be able to demonstrate the affiliate lag does not result in any unintended gain or loss to the affiliated group as a whole or to the different customers served. In this regard, AUMA/EDM/CG disagreed with ATCO Pipelines' statement that lag days for both affiliates and non-affiliate transactions should reflect actual clearance dates. AUMA/EDM/CG argued that to the extent actual clearance dates do not reflect commercial reality, a suitable proxy should be used to reflect the commercial yardstick for leads and lags. AUMA/EDM/CG submitted that the affiliate lag (other than I-Tek) should be increased to 35.50 days to reflect the commercial reality of what it would be if the same services were provided by an arms length entity.

AUMA/EDM/CG noted that ATCO Pipelines proposes an expense lag of 53.21 days for I-Tek services. This is a negotiated lag and presumably reflects the cost elements included in the pricing of I-Tek services. AUMA/EDM/CG argued that the appropriateness of the costs associated with this expense lag would best be reviewed as part of the benchmarking process for I-Tek services.

AUMA/EDM/CG noted that ATCO Pipelines included a working capital element based on a revenue lag of 20.96 days (5.75 payment lag days plus 15.21 days consumption lag) with respect to receipts from ATCO Gas. ATCO Gas in turn showed a 22.7 day expense lag with respect to payments to ATCO Pipelines. Despite the minor discrepancy in the lag days recorded by the two companies, AUMA/EDM/CG noted the two companies use the same assumption with respect to settlement of affiliate transactions.

AUMA/EDM/CG noted the revenue and expense lags used by ATCO Pipelines and ATCO Gas were substantially offsetting. However, the revenue lag for ATCO Gas is substantially lower than for other distributing companies or the producers. AUMA/EDM/CG noted that the customers of ATCO Gas are not the same as those of ATCO Pipelines and lags not reflecting commercial reality may be unfair to the customers of ATCO Gas. Therefore, for purposes of this Decision, AUMA/EDM/CG recommended that the revenue lag for ATCO Gas be made comparable to other distributing companies.

AUMA/EDM/CG argued that this adjustment should only be made provided a corresponding adjustment extending the lag on payment to ATCO Pipelines is made in ATCO Gas' working capital calculation for 2003 and 2004.

On the issue of Line Pack, AUMA/EDM/CG submitted that until a value for maintenance Line Pack is negotiated and the value transferred to customers, maintenance Line Pack should be excluded from rate base. Accordingly, maintenance Line Pack should not be included in working capital for 2003 and 2004.

Calgary

Calgary submitted that the lags for affiliates should be based upon the lags approved in Decision 2001-97. Calgary argued that ATCO should not be allowed to influence the working capital requirements amongst its subsidiaries by determining the settlement date. For example, there was no reason why the date on which ATCO Pipelines settles with other affiliates should be any different than settlements with arms-length third parties. Calgary submitted that since ATCO Pipelines and ATCO Gas were part of the same corporation there should be no lag between the two for working capital purposes.

Calgary noted that ATCO Pipelines proposed to include Line Pack in its working capital in 2003. The amount was based on $5.00 per GJ for a total of $3.5 million. However, in 2003, as a result of the mid-year convention, the amount included in working capital was $1.75 million. Calgary noted that ATCO Pipelines acknowledged that it had notionally "purchased" the Line Pack from customers, and had made no provision to credit the customers from whom the gas was obtained. It was acknowledged by ATCO Pipelines that customers had supplied the Line Pack over the years from unaccounted for gas[25]. Calgary submitted that it is not appropriate that customers should pay a return on the Line Pack when they have already paid for it directly. Further, although ATCO Pipelines claimed it was not attempting to increase its rate base, as a result of inclusion of Line Pack in rate base, Calgary claimed that the Applicant's costs would increase at a time when it purported to be concerned about its competitive situation vis a vis NGTL. Calgary submitted that there was no economic benefit to ratepayers in ATCO Pipelines owning the Line Pack and that shippers on the system should be totally responsible for supplying their own Line Pack and balancing their own accounts. Calgary argued that shippers on the pipeline currently have obligations to be in balance and provide or pay for unaccounted for gas and that Line Pack was an obligation of the shipper. Calgary submitted that ATCO Pipelines should focus on enforcing its current tariff provisions and compelling shippers to comply with the tariff thus managing both issues rather than artificially building rate base, which was not required to meet system needs and was actually the responsibility of the shippers.

FGA

FGA submitted that ATCO Pipelines intended to make an application to acquire the Line Pack from customers later this year, and to place the value of Line Pack in rate base through NWC. FGA considered this proposal acceptable.

FGA noted that ATCO Pipelines placed $1.7 million in NWC for the test year 2003 and $3.5 million for the 2004 test year. This amount was based on approximately 701 TJ of Line

[25] Tr., p. 70 and 187

Pack gas on average in the system, at a forecast price of gas in the \$5/GJ range[26] with ATCO Pipelines acquiring the Line Pack during 2003. FGA considered this amount to be a reasonable placeholder for the purpose of this proceeding. However, given that ATCO Pipelines would soon make an application to acquire the Line Pack, FGA submitted that the mid-year price for 2003 NWC should be based on the current value of the Line Pack at the time of acquisition. When additions to Line Pack are made as a result of future system expansions, the additions should be valued at the price of gas at the time the project is put into service so that all the Line Pack is valued at original cost.

Views of the Board

The Board agrees with ATCO that revising the O&M expense lag to reflect the payroll and payroll related expense lag calculation to include incentives does not materially affect the O&M expense lag. However, the Board believes that a revision to the payroll and payroll related expense lag provides a more accurate account of the lead lag study, and in the Board's view causes no administrative burden to ATCO. Therefore, the Board directs ATCO to revise the Payroll and Payroll related lag days to 13.89 days as indicated in Exhibit 29-18, and revise the O&M expense lag to reflect this change.

The Board notes that ATCO Pipelines requested approval for a 5.75 day lag with respect to affiliate lags, which reflects actual payment terms, while requesting that the Board reconsider its direction in Decision 2001-97 requiring that ATCO Pipelines recalculate its lead/lag study with the application of a zero lag to ATCO Pipelines transactions with AGS. The Board notes that ATCO's lead/lag study incorporates a revenue lag with respect to transactions with ATCO Gas. The Board agrees with Calgary's submission that since ATCO Pipelines and ATCO Gas are part of the same corporation, there should be no cash lag between the two divisions for working capital purposes. Accordingly, the Board directs ATCO to recalculate its lead/lag study with the application of a zero lag to transactions with ATCO Gas.

The Board notes the different treatment between payments to affiliates and other payments in the lead/lag study. Specifically, ATCO's proposed expense lag for affiliate payments (excluding I-Tek) is 20.96 days, as opposed to 35.50 days for other O&M expenses. The Board also notes that the expense lag for payments for I-Tek services is 53.21 days. The Board considers that, for the purposes of calculating the NWC requirement, there is no reason why the lag days for payments to affiliates should be any less than the lag relating to payments for arms length transactions. Accordingly, the Board directs ATCO to recalculate the NWC balance using an expense lag of 35.50 days for payments for affiliate services (excluding I-Tek).

With regards to I-Tek, the Board notes that ATCO Pipelines argued that should the Board direct it to revise the lag days for affiliates to be identical to O&M expenses, then the lag days for I-Tek should also be adjusted to 35.50 days from the contractually agreed lag of 53.21. The Board notes that AUMA/EDM/CG argued that this was a negotiated lag and presumably reflected the cost elements included in the pricing of I-Tek services, and the appropriateness of the costs associated with this expense lag would best be reviewed as part of the benchmarking process for I-Tek services. The Board believes that to remain consistent and fair in the treatment of affiliate transactions as it relates to the lead-lag study and NWC, I-Tek should be treated no differently

[26] CG.AP-61

than any other affiliate service. Therefore, the Board directs ATCO to revise its I-Tek Services lag to 35.50 days, consistent with other affiliate and non-affiliate transactions.

On the issue of Line Pack, the Board notes ATCO Pipelines' acknowledgment that customers had supplied the line pack over the years from unaccounted for gas.[27] The Board agrees with the submission of Calgary that ATCO has failed to illustrate the benefits of the inclusion of Line Pack in NWC to customers. The Board considers that the inclusion of Line Pack inflates rate base and related costs to customers on an asset that was supplied by customers over the years from unaccounted for gas. The Board agrees with Calgary that there is no economic benefit to ratepayers in ATCO Pipelines owning the Line Pack. Therefore, the Board denies the acquisition of Line Pack to be added to inventory in NWC. The Board directs ATCO Pipelines, in its Refiling, to remove the amounts from the mid-year NWC provided in the test years for the proposed acquisition of Line Pack.

3 COST OF CAPITAL AND CAPITAL STRUCTURE

3.1 Cost of Capital

3.1.1 Allocation of Debt, Preferred Shares and Common Equity Between APN and APS

Views of ATCO Pipelines

ATCO Pipelines applied for slightly different levels of actual equity, debt, and preferred equity between APS and APN as set out in the following table.

Table 15. Forecast Actual Capital Structure Proportions

	APN 2003	APS 2003	APN 2004	APS 2004
Long-Term Debt	0.493960	0.455714	0.441870	0.444335
Preferred Shares	0.058580	0.060231	0.058130	0.055662
Common Equity	0.447460	0.484055	0.500000	0.500003

ATCO Pipelines indicated that APS and APN effectively inherited different initial capital structures when they were split out of Canadian Western Natural Gas and Northwestern Utilities Ltd., respectively. Subsequently their capital needs were met through Canadian Utilities Limited (CUL). For 2003 and 2004, the capital structures were adjusted toward the appropriate levels by transferring $10,000,000 of 4.84% long-term debt from APN to APS.

Views of AUMA/EDM/CG

AUMA/EDM/CG recommended that separate equity ratios be maintained for APN and APS. Furthermore, it did not support the transfer of $10,000,000 of 4.84% debt from APN to APS and questioned why a market long-term interest rate would not be used. AUMA/EDM/CG indicated that ATCO Pipelines had not explained why the particular 4.84% debenture was chosen for the transfer from APN to APS.

27 Tr., p. 70 and 187

Views of the Board

The Board notes that ATCO Pipelines forecast a 2003 actual equity ratio of 44.7% for APN and 48.4% for APS, while requesting a deemed equity level of 50%. ATCO Pipelines forecast that the actual equity ratio would reach the proposed deemed level of 50.0% in 2004.

In the Board's view the interest rate used on the $10,000,000 transfer between APN and APS is not a particularly significant item overall. A 1% increase in the interest rate would amount to an increase of $100,000 in the revenue requirement of APS and a $100,000 decrease in the revenue requirement of APN. The Board considers that ATCO Pipelines would have had little incentive to use an artificially low interest rate since the transfer between customer groups does not affect the shareholder.

In the Board's view, ATCO Pipelines' allocation of debt, common equity and preferred shares between APN and APS is reasonable. A subsequent section of this Decision deals with the appropriate common equity ratio.

Therefore the Board approves the proportion of debt and preferred shares of APN and APS as set out by ATCO Pipelines in the Application, adjusted as necessary by the Board's determination of the deemed common equity ratio.

The Board notes a significant divergence in the Application between the mid-year capitalization and mid-year Rate Base. The Board directs ATCO Pipelines, at the next GRA, to address this issue.

3.1.2 Debt and Preferred Share Cost Rates

Views of ATCO Pipelines

ATCO Pipelines argued that its financing costs, which reflected the long established practice of combining debt and preferred share financings through CUL, should be approved as filed. ATCO Pipelines argued that this provided the lowest costs to customers. In the Application, ATCO Pipelines proposed the mid-year embedded costs of debt and preferred shares indicated in the following table.

Table 16. Debt and Preferred Share Cost Rates

	2003	2004
Long Term Debt	7.5603%	7.5114%
Preferred Shares	5.2560%	5.2733%

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG did not object to the embedded cost of debt proposed by ATCO Pipelines. However, it did object to a proposed transfer of $10,000,000 in 4.84% debt from APN to APS. This issue is dealt with in Section 4.1.2 of this Decision.

Views of the Board

The Board notes that there was no opposition to ATCO Pipelines' proposed embedded costs of debt and preferred shares. The Board also considers that these costs appear reasonable. Therefore

the Board approves ATCO Pipelines' proposed embedded costs of debt and preferred shares as set out in the Application.

3.1.3 Appropriate Return on Equity

This section addresses the appropriate return or profit on the shareholders' common equity investment. The approved return on common equity (ROE) will be included in ATCO Pipelines' forecast revenue requirement. The actual ROE will differ from the approved level due to the inevitable variances from forecast revenues and expenses.

Table 17. Summary of Return on Equity Recommendations by Parties

	Recommended ROE (%)
ATCO Pipelines Applied For	11.5
AUMA/EDM/CG	8.5-9.0
Calgary	8.5
CAPP	9.0 - 9.4
Cargill	8.0 - 9.0

Views of ATCO Pipelines

ATCO Pipelines recommended a return on equity of no less than 11.5% for 2003.

ATCO Pipelines focused on several forms of the Equity Risk Premium (ERP) test, with confirmation from the discounted cash flow (DCF) test. ATCO Pipelines focused the bulk of its ERP evidence on the Capital Asset Pricing Model (CAPM) method, but also provided evidence using a DCF based ERP test and using actual historically achieved utility risk premiums. ATCO Pipelines' ERP test recommendation used all three forms of the ERP test and indicated a required ROE of 11 – 11.75% based on a 6% risk free rate, an ATCO Pipelines risk premium of 4.5-5.25%, plus 0.50% for financing flexibility. The DCF test, using U.S. gas distributors as a proxy, indicated a required ROE of 11% for an average risk Canadian utility. ATCO Pipelines required a 0.50% premium plus the 0.50% for financing flexibility for a total DCF test ROE requirement of 12.0%.

ATCO Pipelines argued that the ERP is a test of return on market value, not book value. It is a forward-looking concept reflecting investors' willingness to take risks and their expectations of inflation, productivity and profitability.

ATCO Pipelines argued that the estimation of the ERP is not an exact science and therefore requires evaluation of alternative risk premium estimation approaches.

ATCO Pipelines indicated that the Capital Asset Pricing Model (CAPM) method is rigorous and formal, but that all of the expert witnesses submitting evidence in this proceeding recognized it had limitations, particularly with respect to the relative risk measure, beta. ATCO Pipelines provided a quote from a noted finance author[28] that indicated that measured betas have not done well in predicting return and that betas are not stable from period to period.

ATCO Pipelines noted that its risk free rate was based on the December 2002 consensus forecast and that it was supported by Calgary.

28 Burton Malkiel, A Random Walk Down Wall Street, New York: W.W. Norton & Co., 1999

ATCO Pipelines indicated that the use of the achieved risk premiums in Canada as an estimate of the required risk premium should be undertaken with caution for the following reasons:

- Canadian investment opportunities are not limited to domestic opportunities;
- The historic resource orientation of the Canadian economy casts doubt on the premise that the data are likely to be a good proxy for future returns;
- The Canadian "Market Portfolio" has been unduly influenced by a few large companies i.e. Nortel, BCE and JDS Uniphase;
- The Canadian equity market has undergone significant structural change;
- The Canadian market remains significantly less diversified than the U.S. market; and
- Improved economic fundaments in Canada suggest that the historic differential between Canadian and U.S. bonds is not expected to persist in the future.

ATCO Pipelines argued that the U.S. equity market is a relevant historical benchmark for estimating the Canadian equity risk premium because of its diversified nature and the close relationship between the two countries' capital markets. The relevance of U.S. markets has been recognized by the CTRC[29] and by the Regie de L'Energie de Quebec.[30] ATCO Pipelines noted that Calgary's experts have confirmed the relevance of looking at U.S. data as a guide to seeing whether or not the Canadian estimates are reasonable.

In Reply Argument, ATCO Pipelines agreed that current Canadian market prices reflect international factors, but argued that the historic Canadian risk premiums do not. ATCO Pipelines noted that excluding U.S. data for ATCO Pipelines on the basis that its shareholders are predominantly Canadian is not supported by any theory, and would imply that the market risk premium differs for different companies in Canada depending on who owns the shares.

ATCO Pipelines argued that its analysis of the historic risk premiums for both Canadian and U.S. utilities supports an expected equity risk premium for an average risk Canadian utility of approximately 4.75 – 5.25%.

ATCO Pipelines estimated the forward-looking utility risk premium at 4.5 - 4.7% by applying the DCF method to a sample of U.S. local gas distribution companies (LDCs) for the period 1993-2002 using the consensus of analyst forecasts of long-term normalized earnings growth, and the corresponding expected dividend yield. Canadian data was not available. ATCO Pipelines accepted that analysts' forecasts have been optimistic, but noted that as long as investors believe the forecasts, then they are unbiased estimates reflecting investor expectations. The expected earnings growth rate for the LDCs from 1993-2002 was 5.6%, which was similar to the expected long-term nominal rate of growth in the U.S. economy over the same period. ATCO Pipelines noted that CAPP's experts recommended downward adjustment to analyst growth estimates was not based on any rigorous analysis, as admitted in testimony.

ATCO Pipelines argued that the goal in setting beta is to establish a beta that is predictive of return requirements and not simply to predict the next beta. ATCO Pipelines argued that the recent observed low levels of utility betas are not appropriate for determining the required rate of return as they were artificially lowered by the technology bubble, as also indicated by Calgary's

[29] CRTC Decision 98-2
[30] Regie de L'Energie de Quebec Decision 99-150

experts. ATCO Pipelines' expert's recognition of total market risk (including both diversifiable and non-diversifiable risk), as measured by the standard deviation of market returns in conjunction with beta, leads to the conclusion that a relative risk adjustment of 0.60 –0.65 is reasonable for an average risk utility. ATCO Pipelines argued that the 0.60 to 0.65 beta is also consistent with Canadian and U.S low risk utility actual beta, adjusted towards one, which is the practice used in published beta estimates such as provided by Value Line and Bloomberg. ATCO Pipelines' 0.60 – 0.65 figure is consistent with Calgary's long-run average historical beta estimate of 0.62, however, ATCO Pipelines noted the frailties of relying solely on raw betas. ATCO Pipelines argued that it has higher business risk and financial risk compared to an average risk Canadian utility or U.S. LDC. Using the "Hamada" formula, the specific beta for ATCO Pipelines was adjusted upwards to 0.70, to recognize ATCO Pipelines' lower than average equity ratio. Based on this beta and all of its other analysis, the appropriate risk premium for ATCO Pipelines was estimated to be 4.5 to 5.25%. ATCO Pipelines noted weaknesses in Calgary's and CAPP's lower beta estimates. ATCO Pipelines noted that, despite intervener suggestions to the contrary, its expert's adjusted betas were in fact in conformance with the stated approach of Value Line.

ATCO Pipelines argued that Calgary's multi-factor analysis should be given no weight given that the historic period used in the analysis was a period of very high interest rate volatility, whereas their forecast of the test period is for very low interest rate volatility. ATCO Pipelines noted that a study cited by Calgary also indicates that the CAPM consistently predicts lower capital costs for the regulated utilities than their historical cost. The multi-factor results found by the authors of the study noted by Calgary were on average close to 100 basis points higher than the CAPM results and these authors found these results to be more reasonable than those of the CAPM.

ATCO Pipelines used the DCF method as a reasonableness check on the equity risk premium results. A sample of low risk U.S. LDCs was used. Earning growth estimates were from "I/B/E/S International" and Zacks and were checked using the Value Line longer-term growth rates. The resulting DCF cost of equity was 11.0% for the U.S. LDCs. For ATCO Pipelines a 0.50% premium was appropriate due to higher risk, for a total DCF required return for ATCO Pipelines of 11.5%, which resulted in a required ROE of 12.0% after adding the financing flexibility amount. ATCO Pipelines noted that an article referenced by the interveners treated analysts and investors as identical. ATCO Pipelines addressed criticisms of the DCF method by noting that all of the models have limitations and CAPM has unrealistic assumptions. For this reason multiple tests should be used.

ATCO Pipelines concluded that the market/book analysis proffered by Calgary provided no insight regarding the reasonableness of the returns allowed by the NEB to TCPL. Price to book ratios include impacts from unregulated operations. In addition ATCO Pipelines argued that price to book ratios should not be compared to 1.0, but rather to those of other companies and to the market indices. ATCO Pipelines noted that TCPL out-earned the NEB formula in 5 of 7 years in a table provided by Calgary's capital markets expert, indicating that this may partially explain the high price-to-book ratios.

ATCO Pipelines recommended that the results of Calgary's income trust data be given no weight in arriving at a fair return for ATCO Pipelines. ATCO Pipelines noted that income trusts are lower risk because they have little or no debt, and this may partially explain their low returns.

ATCO Pipelines recommended a financing flexibility adder of 0.50%. Without this the market/book ratio would approach 1.0. ATCO Pipelines argued that regulation is fundamentally a surrogate for competition. Under competition, market value should trend to replacement cost, not book value.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG recommended a maximum ROE of 9.0%, but indicated that it would defer to the final recommendations of Calgary's experts of 8.5% and CAPP's expert of 9.0%. In Reply Argument AUMA/EDM/CG indicated that on reflection its suggested 9% return was a maximum and might be overly generous, particularly given Calgary's experts' information on the potential to update to a lower risk free rate.

AUMA/EDM/CG argued that financial risk should be reflected in the ROE and that business risk should be reflected in the capital structure. AUMA/EDM/CG argued that ATCO Pipelines had effectively asked the Board to change its traditional equity risk premium method in favor of utilizing the spread between 30-year A-rated utility bonds and 30 year Canada bonds. Any change in the spread was not evidence of a need to "artificially inflate the required return". The relevant question is whether ATCO Pipelines is able to access the equity markets on reasonable terms. There is no compelling evidence to justify changing from the traditional method for calculating an equity risk premium.

AUMA/EDM/CG argued that ATCO Pipelines' use of U.S. data to support the equity risk premium is flawed, and must be discounted to reflect the attractiveness of the Canadian market. ATCO Pipelines' data also does not reflect the recent narrowing of the U.S. market risk premium.

AUMA/EDM/CG argued that ATCO Pipelines' adjustment to the so-called "raw" beta, towards the market average beta of 1.0 is not justified. The mean of the median beta for the seven Electric/Gas Utilities, shown in ATCO Pipelines' expert evidence for the period 1995-1998, was 0.49 and for the TSE 300 Gas/Electric index for the same period was 0.51.

AUMA/EDM/CG supported a risk premium of about 2.65% for ATCO Pipelines, being the mean of the recommendations of Calgary and CAPP's experts.

Calgary

Calgary recommended a return on equity of 8.5%, derived as indicated in the following table.

Table 18. Summary of Calgary's Experts' ROE Recommendation:

Long term Government of Canada yield	6.00%
Risk Premium Method	8.02-8.47%
Multi-factor Model	7.66–7.74%
Overall Recommendation	8.50%
Inherent equity risk premium in final recommendation	2.50%

Calgary indicated that the market risk premium should be forward looking, rather than being a simple average of historical data. Calgary submitted that the recent literature on market risk premiums, summarized on page 42 of the evidence of Calgary's experts, was indicative that both academics and market participants no longer expect the type of returns that were observed in the last 40 to 50 years. Given this recognized change in circumstances, the continued claims of a market risk premium based upon historical data cannot be supported.

In its risk premium method, which was weighted 50% in its final recommendation, Calgary used a market risk premium of 4.5%. Calgary found an actual historical market risk premium of 2.09-2.82% using data from 1957-2001 and 4.10-5.36% using data from 1924-2001. Corroborating evidence from eight studies, which omitted geometric means (which are lower than the arithmetic means supported by Calgary) resulted in a mean market risk premium of 4.34%. Calgary argued that it is clear from these studies that its market risk premium recommendation is quite reasonable. Calgary noted that ATCO Pipelines' market risk premium could only be justified by relying solely on the long-term arithmetic risk premium.

Calgary also provided a multi-factor model which resulted in a required equity return of 7.66 – 7.74% before the flotation allowance. Calgary gave this model a 50% weighting in its final recommendation.

Calgary recommended 6% for the risk free rate.

Calgary indicated that the appropriate beta for ATCO Pipelines was 0.50 based on a range of 0.45 to 0.55. Calgary submitted that Canadian betas should not be adjusted based upon the so-called Value Line/Merrill Lynch approach. Calgary stated that its experts have provided evidence that the utility betas regress to a utility mean of approximately 0.55 rather than to the market mean of one.

As corroborating evidence regarding beta, Calgary provided an analysis of the beta of high-dividend mutual funds. The mean of the dividend fund betas for ten separate rolling periods was 0.55. Calgary noted that the utility shares held within these mutual funds represent the integrated holding companies and are therefore more risky than ATCO Pipelines. Calgary argued that this corroborated the beta of 0.50 that it used.

As corroborating evidence, Calgary provided a DCF model of U.S. utility risk premiums. This produced a utility risk premium in the 1.89 – 2.57% range, which would be added to the risk free rate and increased by a cushion. Calgary also performed a DCF test using its expected nominal GDP growth as the estimated growth rate for the market. This DCF test resulted in a geometric return estimate of 8% for the Canadian market. Calgary noted that the principal problem with the use of the DCF method is the forecast of growth rates. Calgary recommended that the Board not rely on the DCF method, but use it only as a test of reasonableness of recommendations.

Calgary submitted that U.S. data is materially more remote and less probative than the Canadian data, by virtue of differences in taxation of investment returns, and the varying business risks and regulatory differences between jurisdictions. Calgary further noted that the markets for the securities issued to fund ATCO Pipelines are the Canadian markets.

Calgary argued that the high market-to-book ratios of the publicly traded utilities are highly suggestive that the allowed returns are in excess of the market requirements.

Calgary's capital markets expert used the market-to-book ratio as a measure of the reasonableness of the allowed return. He analyzed market to book data and returns of income trusts and concluded that the allowed return on equity should be set at the 8.5% level recommended by Calgary's primary rate of return experts. Calgary noted that the NEB formula allows a return on equity of 9.79% for 2003 and the BCUC formula allows its benchmark low-risk utility to earn 9.42% for 2003. The record is clear that companies subject to these formulas are able to access debt and equity markets. Further, while ATCO Pipelines argues that the high price-to-book value ratio may be the result of non-regulated operations, the consolidated return for TCPL has averaged below the level of the NEB formula when looked at over the last 4,5,6 or 7 years, and yet the high price-to-book ratios persisted in most years.

Regarding income trusts, Calgary's capital market expert indicated that the record was clear that the yield of income funds is dependent on their earned returns and income funds are attracting massive amounts of capital with after tax returns below 6%. Calgary provided detailed evidence as to why income trust return data is relevant and why ATCO Pipelines' rebuttal of this evidence was not valid.

Calgary recommended a 0.50% allowance for flotation and market flexibility.

Calgary argued that ATCO Pipelines' analysis was flawed in that the sample was discontinuous and had composition problems. In addition it was illogical to compare a promised yield to a required return for a number of reasons, including the fact that a promised yield included a default risk and therefore the required return on the bond was below its promised yield.

CAPP

CAPP's expert recommended 9.0% including 0.25% for financing flexibility.

CAPP itself indicated that it would support 9.4% based on a slightly higher beta and a higher financing flexibility allowance.

CAPP's expert argued that the appropriate market risk premium is the arithmetic average over the longest available time period. CAPP's expert argued that attempting to adjust the data to reflect current circumstances is tantamount to attempting to predict the future and this approach should be rejected in favor of a simple average over the longest time period available.

CAPP's expert argued that Canadian data should be used and would reflect global opportunities. If global opportunities were to be explicitly considered, then a world index rather than U.S. data should be used. CAPP's expert argued that world index data might lower the market risk premium due to increased diversification.

CAPP's expert rejected ATCO Pipelines' adjustments of betas toward the market average of 1.0. After adjusting for ATCO Pipelines' small size, CAPP's expert argued that ATCO Pipelines' beta should be 0.45. However, CAPP itself indicated a beta range of 0.515 to 0.54 based on pipeline industry betas and excluding data from 2000-2002, then adjusted for ATCO Pipelines' small size. CAPP's expert rejected ATCO Pipelines' use of U.S. data in determining beta.

CAPP supported 6.0% as the risk free rate.

CAPP's expert rejected ATCO Pipelines' analysis based on increased bond spreads, citing the difference between promised yields on bonds and the expected yield on bonds after accounting for the probability of default.

CAPP's expert argued for a financing flexibility allowance of 0.25% and noted that there is no evidence that ATCO Pipelines has incurred or will incur the flotation costs estimated by its expert. CAPP indicated in argument that it would not object to continued use of the 0.50% financing premium.

CAPP's expert indicated that it is worthwhile to verify the cost of equity by using more than one method. CAPP's expert noted that there is over-optimism in analyst growth factors, but that there is no evidence to show how much of the over-optimism in analyst forecasts is discounted or incorporated into securities prices. CAPP's expert applied decision theory and adjusted ATCO Pipelines' DCF analysis to reduce the growth estimates by 50% of the estimated over-optimism, indicating that the resulting ROE was close to his result obtained by using the equity risk premium approach.

In Reply Argument CAPP rejected ATCO Pipelines' argument for a 0.50% premium to compensate for its higher business and financial risks. CAPP argued that capital market theory is unequivocal in stipulating that only non-diversifiable risk should be incorporated into the cost of equity. In CAPP's view ATCO Pipelines has not shown that the business risks for which it seeks the adjustment are non-diversifiable.

Cargill

Cargill recommended an ROE of 8-9% based on the evidence in this case, taken as a whole.

Cargill argued that when the highly questionable assumptions and adjustments of ATCO Pipelines' expert are stripped away, it appears that the approaches used by the company and intervener witnesses are basically consistent and point to a required equity return in the range of 8-9%.

Regarding the price-to-book ratio, Cargill argued that Calgary's capital markets expert's analysis of book value should frame the Board's evaluation of the more technical ROE evidence. Cargill noted that this evidence indicated high market-to-book ratios, demonstrating that the allowed ROEs generated by the NEB formula are not only adequate, but are generous.

Cargill rejected ATCO Pipelines' argument that utility equity should trade at replacement cost rather than book value. Cargill argued that ATCO Pipelines' expert seemed to be acknowledging the high market-to-book ratios and had attempted to justify them by comparisons to competitive situations where asset values trend towards replacement cost. Cargill argued that the regulatory objective has always been to establish a fair return on book value and justifications based on comparisons to competitive firm's assets being valued at replacement cost were inappropriate.

Regarding the use of U.S. market data, Cargill argued that it was perplexed as to why the Board would even consider looking at U.S. data to determine the cost of equity for a Canadian utility with no U.S. operations and with Canadian ownership that raises its capital in Canadian markets. Cargill argued that other Canadian companies and the Canadian market would intuitively seem

to provide the best available data to determine ATCO Pipelines' cost of equity. In addition, Cargill noted that Calgary and CAPP had provided additional technical reasons why the use of U.S. data was inappropriate.

Cargill rejected the use of the DCF method due to the unreliability of analyst growth forecasts.

FGA

FGA noted that the experts did not update their recommended risk free rates to the latest information available at the time of the hearing. FGA noted Calgary's comment that it refrained from such an update in order to be consistent with three other recent GRAs before the Board, based on much the same evidence. FGA argued that the experts should have updated their risk free rates and taken into account that the Board is only dealing with 2003 in the decision. FGA submitted that the lower end of CAPP's expert's forecast risk-free rate of 5.7% is the appropriate forecast rate, as it most closely follows the current information available at the time of the hearing.

FGA noted that ATCO Pipelines' expert has expressed reservations about the DCF method in past hearings and that these limitations were discussed on the record in this proceeding. FGA submitted that the inherent limitations in the DCF test have not been overcome, including its unrealistic assumptions. FGA also provided specific criticisms of the computation of ATCO Pipelines' DCF test. FGA submitted that no weight should be given to ATCO Pipelines' expert's DCF test.

Views of the Board

In this section, the Board will address the appropriate rate of ROE for ATCO Pipelines, by examining the following factors:

- The Role of U.S. Data
- Market-to-Book Ratio
- Income Trust Data
- The Multi-factor Model
- The DCF Method
- Equity Risk Premium Methods
- CAPM equity risk premium results
- Risk Free Rate
- Beta
- Market Risk Premium
- Flotation Allowance
- Other Considerations
- Appropriate ROE for ATCO Pipelines

The Role of U.S. Data

The Board notes the arguments of ATCO Pipelines that U.S. data should be considered in setting the ROE of ATCO Pipelines. It cited globalization of investment opportunities, the undue influence of several large stocks on Canadian market data and changes in the Canadian economy and its relationship to the U.S. economy. The Board also notes the arguments of Calgary regarding differing tax structures and regulatory environments; CAPP's argument that, under

standard finance theory, globalization should reduce rather than increase risk premiums; and Cargill's argument that use of U.S. data is patently inappropriate given that ATCO Pipelines operates in Canada, raises money in Canada and is largely owned by Canadians.

The Board agrees with Calgary that Canadian data provides a sufficient indication of the Canadian market's required ROE. In particular, the Board notes the differing tax structures and agrees that the impact of international opportunities is reflected in the Canadian data, to an appropriate degree.

Therefore the Board considerers that it is not appropriate to place significant weight on U.S. data, but considers that U.S. data can be used as a reasonableness check.

Market-To-Book Ratio

The Board notes that Calgary did not directly use its market-to-book ratio evidence in calculating its proposed 8.50% ROE, but instead treated it as corroborating evidence.

The Board agrees with Calgary that consistently high market-to-book ratios for regulated utilities may potentially constitute evidence that awarded returns may be generous. However, the usefulness of this analysis is diminished by the dearth of pure-play utilities trading on the Canadian stock exchanges and a relative lack of pure-play utility merger and acquisition data.

In addition, when investors bid up holding company utility stock prices, it is not clear to the Board if this behaviour indicates that they are accepting and require a lower return than awarded, or instead indicates, as suggested by ATCO Pipelines, that they expect the holding company ROE to exceed the awarded return of its regulated utility subsidiary(s). For these reasons, the Board has placed little weight on market-to-book ratio data, in this proceeding. However, the Board notes that directionally, this evidence supports lower rather than higher returns.

Income Trust Data

The Board notes that Calgary did not directly use its income trust evidence in calculating its proposed 8.50% ROE, but instead treated it as corroborating evidence. The Board understands why Calgary would choose such evidence directionally, given the large amounts of capital migrating to income trusts in the market.

However, in this Decision the Board is not persuaded to Calgary's implicit view that income trust investors were expecting returns below 6% and therefore utility investors should be taken to accept returns of this level. In particular, the Board is not persuaded that investors in utilities such as ATCO Pipelines or its parent expect their returns to equal the ROEs of the income trusts. The Board has therefore placed little weight on the income trust return data in this proceeding.

Multi-factor Model

The Board considers Calgary's Multi-factor model to have theoretical merit. In particular, the Board recognizes that the CAPM model is being applied to a market such as the TSX that excludes bonds, when the theory indicates that the market index should include bonds. In theory, the Multi-factor model may alleviate this problem. However, the relatively short data period of 1982 to 2001, which was a period of extreme interest rate volatility, may not be representative, and the fact that Calgary's experts find it necessary to replace the actual term premium with a 1% figure leaves the Board with some doubt about the results of this model, at this time.

In the circumstances, the Board does not consider it appropriate to place 50% weighting on Calgary's Multi-factor Model calculation as recommended by Calgary. Rather, the Board has placed very little weight on this calculation.

DCF Method

The Board shares Cargill's and CAPP's concerns regarding the optimistic nature of analyst growth forecasts with respect to the reliability of the DCF method, and notes that ATCO Pipelines has not denied that the optimism exists. The Board does not agree with ATCO Pipelines' argument that over-optimism would not be an issue as long as investors legitimately believed the over-optimism and priced utility securities accordingly. In the Board's view it would not be reasonable to award a return on the book value of equity that was the result of growth forecasts that were acknowledged to be over-optimistic.

Therefore, the Board has not placed any direct weight on the DCF results that are based on analyst growth forecasts.

The Board notes Calgary's alternative DCF analysis which used a nominal GDP growth forecast as a reasonableness test for the market return. In the Board's view this approach has merit. Therefore the Board has considered this result in reviewing the reasonableness of its ROE determination.

Equity Risk Premium Methods

Historically, the Board has placed most weight on the CAPM equity risk premium method. In this proceeding, ATCO Pipelines focused on several forms of the equity risk premium method, including CAPM, and used the DCF test for confirmation. The CAPM form of the equity risk premium approach was given 50% weight in Calgary's recommended ROE. CAPP used the CAPM method with confirmation by the DCF method. Cargill supported the use of the CAPM method and rejected the use of the DCF method. FGA also rejected the use of the DCF method. In summary while a number of experts saw value in other methods, and felt that reliance on a single test was inappropriate, there was relatively broad support for substantial, but not exclusive, reliance on the CAPM equity risk premium method.

In addition the Board has specific concerns regarding the results of the Multi-factor Model and the DCF methods. These concerns are identified elsewhere in this section.

The Board notes that ATCO Pipelines also presented results from a DCF equity risk premium test. The Board has not placed significant weight on this result due to its reliance on analyst earnings growth estimates. As indicated above, the Board did give some consideration to Calgary's alternative DCF analysis, which relied on GDP growth estimates and not on growth estimates for individual firms, as a check on reasonableness.

The Board also notes that ATCO Pipelines presented evidence on the historic achieved utility risk premiums in the U.S. and Canada. The Board believes that this method may suffer from circularity and notes that ATCO Pipelines had confirmed that the mid-point of the achieved Canadian utility risk premium was above the overall market risk premium for the period used. In the Board's view it is not reasonable to expect utility returns to exceed market returns in the future. Consequently, the Board did not place weight on the historic utility achieved risk premium.

The Board considers that a fair ROE can most soundly be determined by reliance on the CAPM equity risk premium method. However, the Board recognizes that the results from the CAPM method should not be accepted if they are outside the bounds of reasonableness suggested by other considerations.

CAPM Equity Risk Premium Method Results

Based on its historical use and broad, although not complete, support among the cost-of-capital experts, the Board considers that, despite some concerns regarding CAPM expressed by ATCO Pipelines, a fair ROE can be determined primarily by reliance on the CAPM equity risk premium method. However, the Board will test the reasonableness of the result through other considerations.

The Board will determine an ROE using the CAPM equity risk premium method by assessing the following factors:

- Risk Free Rate
- Beta
- Market Risk Premium
- Flotation Allowance
- Other Considerations

Risk Free Rate

The Board notes that there was broad support for the use of a 6.0% risk free rate.

Accordingly, the Board will utilize a risk free rate of 6.0% in its determinations in this Decision.

Beta

The Board notes that the parties put forward somewhat disparate positions regarding the range of beta. The Board agrees with ATCO Pipelines' assessment that the goal in setting beta is not simply to predict the next beta. Instead, the Board believes that the goal in setting beta is to reflect investors' reasonable expectations of relative risk and that this is best achieved by reflecting a longer term view.

ATCO Pipelines argued for a beta of 0.60-0.65 for an average risk utility and 0.70 for ATCO Pipelines. ATCO Pipelines' beta was partly based on use of U.S. data.

The Board agrees with Calgary that the appropriate beta for ATCO Pipelines was 0.50 based on a range of 0.45 to 0.55. Calgary also indicated that the long run average utility beta has been 0.62 and that the long-run regression tendency is about 0.55.

CAPP's expert argued that ATCO Pipelines' beta should be 0.45. However, CAPP itself argued for a beta of 0.515 to 0.54.

In the Board's view, due to small sample sizes, the beta for individual functions such as pipelines are more difficult to estimate than the average regulated utility beta. This is particularly true in the case of ATCO Pipelines, which would not necessarily be expected to have a beta similar to large gas pipelines. In addition, the Board notes its practice of adopting an ROE consistent with other utilities and, where necessary, adjusting for risk differentials in the equity ratio. Therefore,

the Board finds it reasonable that the beta used in the ROE calculation be based on an average risk utility.

The Board considers that based on the record before it and the expert recommendations presented in this proceeding, the evidence supports a beta for ATCO Pipelines of 0.55.

Market Risk Premium

Calgary provided a market risk premium figure of 2.1 – 2.8% using data from 1956- 2001, and then adjusted this to a final figure of 4.5%. Calgary also found an actual historical market risk premium of 4.10-5.36% using data from 1924-2001. Calgary indicated that for historic data, the arithmetic premium rather than the geometric premium was most appropriate as the estimate for the next year's return, but that adjustments should be made for changes in circumstances. In its summary table, as revised during the hearing, Calgary provided a Canadian arithmetic risk premium of 6.00% based on data from 1900-2000. Calgary also provided, in Exhibit 29-65, a number of corroborating academic studies to demonstrate that their 4.5% figure was not unreasonable.

While strongly recommending against sole reliance on historic Canadian data, ATCO Pipelines' expert indicated that the arithmetic average post-World War II Canadian risk premium was 5.5%.

CAPP's expert indicated that the Canadian market risk premium was between 5.5 and 5.7%. This estimate relied on two studies. The first study was a Canadian Institute of Actuaries report using data from 1947—2001. The second study was by Dimson, Marsh and Staunton and indicated a market risk premium of 5.7% for Canada.

The Board has reviewed Calgary's evidence that prospective studies indicate a lower risk premium. The Board notes Calgary's evidence that academic prospective studies suggest an equity risk premium considerably smaller than the historic level. Therefore, the Board considers it possible that directionally the 5.5% required market risk premium estimate for 2003 could be high rather than low. However, historically, the Board has placed most weight on Canadian market risk premium data, using the arithmetic mean. Given the relatively close agreement among the experts regarding the Canadian arithmetic risk premium, the Board accepts ATCO Pipelines' expert's historical figure for the Canadian risk premium of 5.5%. The Board considers that this is a reasonable estimate of the required Canadian market risk premium for 2003.

Flotation Allowance

The Board notes that both Calgary and ATCO Pipelines applied a flotation allowance of 0.50%, while CAPP's expert recommended a flotation allowance of 0.25%. Given that the Applicant and the Interveners largely supported it, the Board will use a flotation allowance of 0.50% for the purposes of this Decision.

Other Considerations

Using the CAPM method, which is the method that it has placed most weight on in the past few years, the Board calculates an ROE of 9.5%. This is based on the components discussed above – i.e. a risk free rate of 6.0%, a market risk premium of 5.5%, a beta of 0.55%, and a flotation allowance of 0.50%. This calculation is further detailed in Table 19 below.

Prior to finalizing its ROE award, the Board believes that it is beneficial to consider the reasonableness of a 9.5% ROE, based on considerations other than the CAPM method.

The Board notes ATCO Pipelines' argument that U.S. awarded returns are higher than 9.5%. Directionally, this indicates that the 9.5% return could be considered low on that basis. However, a number of other reasonableness factors do not support this conclusion.

The Board notes Calgary's evidence that the NEB formula ROE return for 2003 results in an ROE of 9.79% and that the BCUC formula allows its benchmark low-risk utility to earn 9.42%. The Board considers that this is indicative that an ROE of 9.5% for ATCO Pipelines is not unreasonable.

The Board also notes Calgary's evidence that utility holding companies with significant regulated operations are trading at high market-to-book ratios. This provides added comfort to the Board that a return that is similar to the awards of the NEB and other Canadian regulators is not low.

The Board notes Calgary's application of the DCF method to the market as a whole, which resulted in a geometric Canadian market return of 8.0%. An equivalent arithmetic return would be somewhat higher depending on the assumed volatility. The Board notes that this version of the DCF method does not rely on analyst earnings forecasts, but rather on forecasts for real GDP growth and for inflation. The Board notes that this method directly considers prospective return expectations, while the CAPM method is based on historical experience. The Board has not relied on this method, but believes that it provides further comfort that a return for ATCO Pipelines of 9.5% is not low.

In the Board's view, the above reasonableness checks on balance confirm that the 9.5% ROE calculated by the CAPM method is a reasonable return for ATCO Pipelines.

Appropriate ROE for ATCO Pipelines

The Board had concerns regarding the reliance on analyst estimates associated with the DCF method. The Board also had concerns regarding the Multi-factor Model, as noted earlier in this Section. The Board notes that the CAPM method continues to have the broadest level of support among the experts. The Board calculated an ROE based on the CAPM method and then considered the reasonableness of the result based on other factors addressed by parties in this proceeding. Therefore Board considers that a fair ROE for ATCO Pipelines has been determined primarily, but not exclusively, using the CAPM method.

The Board considers that an appropriate ROE for ATCO Pipelines is 9.5% for 2003 and as a placeholder for 2004, in respect of which the final determination of ROE would be made in accordance with the findings in the Generic Cost of Capital proceeding.

The ROE of 9.5% is calculated using the CAPM equity risk premium method as follows:

Table 19. Board Approved – ROE and Components (%, except beta)

	Board Approved
Long-term risk free rate	6.0
Canadian Market Risk Premium Estimate	5.50
Beta or Relative Risk Factor	0.55
Utility Risk Premium (Market x Beta)	3.0
Flotation Allowance	0.5
Total ROE	9.5

The Board directs ATCO Pipelines, in its Refiling, to use, for 2003, a return on common equity of 9.5% for purposes of calculating the revenue requirement. The ROE for 2004 will be a placeholder amount pending the outcome of the Generic Cost of Capital decision.

3.2 Appropriate Capital Structure

This section addresses the appropriate capital structure, which is the %age or ratio of ATCO Pipelines' financing from each of three sources: common equity, preferred share equity, and debt.

3.2.1 Combined or Separate Deemed Capital Structures for APN and APS

Views of ATCO Pipelines

ATCO Pipelines proposed to adopt a single capital structure, arguing that there is no benefit to separately determining capital structures for APN and APS that would justify the increased costs. ATCO Pipelines' expert indicated that APN and APS are of similar enough risk not to differentiate between the two in terms of capital structure. ATCO Pipelines also indicated that a single capital structure is consistent with past approaches.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG recommended that the Board determine separate capital structures for APS and APN. AUMA/EDM/CG indicated that if the Board cannot find a basis to differentiate the risks, then it would not be adverse to the Board making a finding of the same deemed equity component for APS and APN.

AUMA/EDM/CG argued that separate capital structures are consistent with its recommendation that APN and APS maintain separate revenue requirements and rates. AUMA/EDM/CG argued that APS is of higher risk than APN, but noted that the intervener experts were divided in their opinions as to which of APN or APS was more risky.

Calgary

Calgary recommended that the Board approve separate capital structures for each of APS and APN. Calgary argued that business risks differ between APN and APS due to differing proportions of service provided to gas distribution customers. Calgary argued that the use of separate capital structures, given differences in risk, would prevent cross subsidization.

IGCAA

IGCAA recommended that the Board apply the same capital structure to APN and APS. IGCAA argued that APN faces somewhat less business risk than APS because the competing NGTL tolls are generally higher in the North than in the South. IGCAA argued that by combining the two capital structures the greater risk ATCO Pipelines faced in the 2001 GRA because of the NGTL Products and Pricing decision is effectively neutralized.

Views of the Board

In the Board's view, basic diversification theory suggests that the combined business risk should be slightly lower than the sum of the parts.

The Board agrees with ATCO Pipelines' argument that costs will be lower with a combined capital structure and any benefits of separate structures do not outweigh the additional cost and the additional uncertainty in arriving at fair separate levels of capital structure.

The Board therefore directs ATCO Pipelines to use the same deemed common equity ratio for APN and APS.

3.2.2 Common Equity Ratio

The pre-tax cost of common equity is approximately twice as high as the pre-tax cost of debt. Therefore, customers generally prefer a lower equity ratio because of the higher cost of equity as opposed to debt. The utility generally prefers a higher equity ratio to ensure an adequate credit rating on its debt and to reduce the volatility of net earnings. The Board must balance the interests of all parties in arriving at a fair and equitable equity ratio. In cases where there is little or no contention over the size of the preferred share ratio, the focus of argument tends to be on the common equity ratio, and the debt ratio is set as the residual amount after accounting for both common and preferred equity. The following table summarizes the parties' common equity ratio recommendations.

Table 20. Summary of Common Equity Ratio Recommendations by Parties

	Recommended Common Equity Ratio %
AUMA/EDM/CG	40
Calgary	42
CAPP	38
Cargill	38
AP	50

Views of the Applicant

ATCO Pipelines argued that a 50% common equity ratio was appropriate.

ATCO Pipelines argued that its recommended common equity ratio was compatible with its business risks. ATCO Pipelines estimated that an S&P business risk profile score of no less than 4 would apply to it, based on the fact that, of the four Canadian utilities rated, the average score was 3 and ATCO Pipelines is riskier than an average utility. ATCO Pipelines also considered that U.S. LDCs scored an average 3.5, U.S. Pipelines scored an average 4.3, and that ATCO Pipelines is riskier than a typical U.S. LDC. ATCO Pipelines indicated that based on S&P guidelines, it required a 3.5 to 4.0 interest coverage ratio to get a credit rating similar to that of

CUL, and that this required a 47-55% common equity ratio. ATCO Pipelines stated that its recommended common equity ratio was compatible with a stand-alone credit rating equivalent to that of CUL, and this was appropriate since ATCO Pipelines benefits from the low debt costs of CUL ATCO Pipelines indicated that its recommended common equity ratio would maintain financial integrity and credit worthiness.

ATCO Pipelines indicated that some reliance on U.S. data for the risk profile score was appropriate due to a lack of highly rated Canadian companies and the need to recognize that S&P is globally harmonizing its debt ratings. ATCO Pipelines noted that Calgary criticized the use of U.S. comparables, but then asked the Board to rely on the results from Pacific Northern Gas (PNG). ATCO Pipelines stated that PNG was only one utility regulated by one Board, illustrating the lack of Canadian comparables. ATCO Pipelines argued that Calgary's risk rankings were suspect because ATCO Pipelines scored in the top risk ranking in seven of nine categories, but was considered less risky than oil pipelines which scored in the top risk ranking in only five of the nine categories.

In regard to supply risk, ATCO Pipelines indicated that while there is only a low short-term risk of inability to access supply from any source, this risk could well become significant over the longer-term life of ATCO Pipelines' assets. ATCO Pipelines questioned the degree of certainty that can be placed on the future availability of coal bed methane.

ATCO Pipelines argued that it faces risks that on-system supply will be insufficient. ATCO Pipelines explained that on system supplies generate revenues, but supply from NGTL does not. If on-system supply dwindles, then ATCO Pipelines is reliant on its primary competitor for supply. This scenario could lead to increased rates to load customers, which could lead to bypass. ATCO Pipelines argued that, contrary to intervener arguments, the risks of new supply are relevant since new supply is needed to replace depleted receipt points.

ATCO Pipelines provided evidence of a significant increase in contract terminations effective in 2003 and 2004, including single connected sites where pipeline competition is not the reason for the termination. ATCO Pipelines indicated that it has experienced considerable declines in throughput over the last 24 months, particularly at the singly connected receipt locations. In the view of ATCO Pipelines, competition for available on-system supply has escalated significantly. ATCO Pipelines indicated that dually connected contract supply was 296 TJ/D in 2000, that it reached a high of 519 TJ/D in 2002, and that it was projected to fall to 458 TJ/D in 2003 and 341 TJ/D in 2004. ATCO Pipelines' tolls for dually connected points were only lower than NGTL's at four of sixteen points in 2003, which increased competitive risk, compared to 2001, when ATCO Pipelines' tolls were lower than NGTL's at all eight dually connected points.

In regard to market risk, ATCO Pipelines indicated that its contract with ATCO Gas extends only through 2008, is subject to the risk of franchise loss by ATCO Gas and allows contract demand changes on 12 months notice. ATCO Pipelines stated that Edmonton has contemplated entry into the gas distribution business. Industrial load is at risk of competition from NGTL and in the longer term from the Alliance and the McKenzie Delta Pipelines. Some industrial customers have shut down or switched to coal. Industrial customer load losses impair the ability to receive matching on-system supply. ATCO Pipelines noted that the Board did not rule out

pipeline proliferation in Decision 98-21,[31] wherein the Board stated "In the final analysis, what constitutes undue or excessive duplication is dependent on the individual circumstances of each case." ATCO Pipelines noted that lack of direct access to exports increases its risks.

ATCO Pipelines refuted IGCAA's argument that single connected customer contract terminations are due to rate uncertainty rather than production declines. ATCO Pipelines considered that customers would be foolhardy to terminate contracts in a high gas price environment in the absence of production declines. ATCO Pipelines indicated that the Exchange Deferred Account (EDA) deficits are the result of the dual toll problem, which has not been resolved, and the negative balance increases risk relative to the risks which existed at the time of Decision 2001-97. The magnitude of the EDA balances and the impact on ATCO Pipelines' competitiveness is a significant business risk not previously taken into account.

ATCO Pipelines argued that in 2001 ATCO Pipelines' expert did not take into account the increased risk due to the potential Fort Saskatchewan bypass or NGTL delivery pipelines. Further, Decision 2001-97 did not mention a Fort Saskatchewan bypass threat. ATCO Pipelines argued that while NGTL was unsuccessful in Fort Saskatchewan, it signalled a new level of aggressive competition by NGTL. ATCO Pipelines indicated that well over half of its revenues comes from industrial and producer receipts. Therefore its captive customer base is small and loss of industrial and producer revenue would create risk.

ATCO Pipelines argued that the Muskeg River "removal" did not increase risk since it was never part of the regulated system. In responding to arguments regarding self-imposed risk, ATCO Pipelines indicated that it chose to compete for dual connections rather than die, and therefore this was not a self-imposed risk.

ATCO Pipelines argued that its small size is a disadvantage as it has a smaller customer base to absorb the impact of customer retention pricing, it has less liquidity and market access, and is disadvantaged in negotiated settlements.

ATCO Pipelines indicated that CAPP agreed that there are unresolved regulatory issues that increase risk, and that the current regulatory schedule will not resolve this before mid-2004.

Regarding self imposed risks of revenue variance, ATCO Pipelines said that nowhere in the record of the proceeding had ATCO Pipelines suggested that forecasting risk was a criterion on which its request for appropriate risk compensation was based. Instead, ATCO Pipelines argued that the risks it faces are competition risks. ATCO Pipelines' expert argued that capital structure should not be set based on short-term business risks as suggested by CAPP's expert, and that his approach yielded nonsensical risk rankings. In regard to an intervener recommendation, ATCO Pipelines argued that there was no evidentiary basis to set ATCO Pipelines' equity ratio equal to ATCO Gas's ratio, and that no analysis for this was provided on the record.

[31] Decision 98-21, Imperial Oil Resources Limited Application to Construct and Operate the Thicksilver Pipeline Project, p. 6

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG recommended a 40% equity ratio for ATCO Pipelines. If separate capital structures were used, then AUMA/EDM/CG recommended equity ratios of 38% for APN and 44.5% for APS. In Section 3.2.1 of this Decision, the Board determined that a combined capital structure was appropriate.

AUMA/EDM/CG's expert indicated that the risk of APS has not increased since Decision 2001-97 and therefore its common equity ratio should be left at the previously approved level which it indicated was 46.5% (although the correct figure is 45.5%). AUMA/EDM/CG argued that APN is less risky and would warrant a common equity ratio of 40% and that the combined common equity ratio should be 42%. AUMA/EDM/CG further noted that its expert referred to recent items that reduce risk and noted that other interveners' recommendations were in the range of 38% to 42% for the common equity ratio.

AUMA/EDM/CG argued that while the Western Canadian Sedimentary Basin (WCSB) is a finite supply source, this is not new, and producers' ability to maintain current production is as yet unknown. In AUMA/EDM/CG's view, ATCO Pipelines had effectively indicated that there is a high probability that coal bed methane will be significant, and argued that it was already receiving some coal bed methane. This together with "tight gas" might offset any decline in conventional gas supply.

With respect to competition issues, AUMA/EDM/CG argued that some parts of ATCO Pipelines are distant enough from NGTL to eliminate real competition, and some issues can be dealt with through rate design changes. AUMA/EDM/CG referred to Board Decisions 2001-84[32] and 2002-58[33] and concluded that ATCO Pipelines' risks due to competition with NGTL have not been increasing since 2001. AUMA/EDM/CG argued that regulatory risk should be judged to be decreasing, since NGTL has been directed to file a comprehensive analysis of competition issues and since the Board's letter of June 13, 2003, makes it clear that the Board is determined to bring a resolution to the matter. Further, the ability to use non-standard contracts should reduce ATCO Pipelines' risks. ATCO Pipelines may be able to address its lack of competitiveness on dual connected sites in its upcoming GRA, as it had done in 2001-2002.

AUMA/EDM/CG argued that there is very little real risk of franchise non-renewal since the Board would not likely allow an alternate pipeline. Also it is very unlikely that municipalities would not renew franchises. It is not reasonable for ATCO Pipelines to "remove" the lower risk Muskeg River pipeline from regulated service while claiming its risks are higher.

AUMA/EDM/CG indicated that A-rated gas distributors in Schedule 1 of the evidence of ATCO Pipelines' expert had an average common equity ratio of 37.35%.

With respect to S&P guidelines, AUMA/EDM/CG stated that ATCO Pipelines relied on S&P guidelines that were not tested before the Board. ATCO Pipelines placed too much reliance on

32 Decision 2001-84 Industrial Power Consumers and Cogenerators Association of Alberta – Review & Variance of Decisions U99099 and 2000-3

33 Decision 2002-58 Nova Gas Transmission Ltd. Application to Construct Fort Saskatchewan Extension and Scotford, Josephburg and Astotin Sales Meter Stations

availability of an S&P score, which unduly restricted the number of comparable companies available.

Calgary

Calgary recommended a 42% equity ratio for ATCO Pipelines. If separate capital structures were used, then Calgary recommended equity ratios of 43% for APN and 37% for APS.

Calgary's experts defined business risk as the uncertainty attached to return on capital, which is defined as the firm's earnings before interest and taxes (EBIT) divided by invested capital (the sum of debt, common equity and preferred equity). Calgary's experts indicated that the first tool available to a regulator to manage a firm's risk is the use of deferral accounts; the second tool is to alter the amount of debt financing; and the third tool is to directly alter the rate of return. The use of deferral accounts can provide significant reductions in risk, but their use is relatively more common in Canada than in the U.S. and varies across jurisdictions in Canada. This makes it more difficult to compare the risk levels of various utilities in different jurisdictions.

Calgary's experts indicated that the most important information in comparing risks of pure utilities is a comparison of the actual achieved ROEs to their allowed ROEs.

Calgary's experts studied CUL's disclosure documents and concluded that CUL apparently believed that there were no "non-normal" risks faced by ATCO Pipelines. Calgary's experts concluded that the key normal risk to ATCO Pipelines was the possibility of revenue variability. Calgary's experts therefore calculated their recommended equity ratios for APN and APS based on their revenue sources using 30% common equity for core distribution customer revenue (taking into account the sale of the merchant function) and 50% common equity for both industrial and producer segment revenue.

Calgary's experts indicated that PNG was much riskier than ATCO Pipelines, but that its regulator had dealt with some severe revenue loss problems through the use of deferral accounts and revenue rebalancing across customer classes. PNG was allowed a 36% common equity ratio with a 0.75% additional ROE and this was equivalent to about a 42-48% common equity ratio at the standard ROE. In Calgary's view, ATCO Pipelines should be allowed less common equity since it is less risky.

Calgary indicated that supply risk was not significant and ATCO Pipelines appeared unconcerned given the limited review and study that it had apparently undertaken. Calgary indicated that ATCO Pipelines recovered virtually all of its revenue through fixed charges and therefore its sensitivity to daily/annual throughput was very low. Interpipeline competition has been around for many years and this risk has not changed. With respect to market risk, franchise loss cannot occur because the franchises are not up for renewal during the test period and in any event there are no practical alternative supply pipelines with existing capacity.

Calgary argued that regulatory risk is slightly higher for ATCO Pipelines, compared to an average utility, making its risks low to moderate, rather than low. Regulatory risk, however, was not considered substantial by Calgary owing to investor signals, such as high market to book ratios for regulated utilities and the willingness of AltaLink to purchase assets from TransAlta at a high premium to book value. Based on Calgary's comparison of risk factors of various industries, ATCO Pipelines was more risky than gas utilities, but less risky than oil pipelines.

Calgary stated that small size is not a risk since the holding company raises the capital.

Calgary argued that the use of foreign indices is not warranted since the average RSP investor is only 9.9% invested in foreign assets and Canadian markets already reflect competition with foreign investments.

Calgary submitted that the record is clear that S&P's own ratings do not conform to its guidelines. The Board should not accept the views of S&P as determinative.

CAPP

CAPP recommended a common equity ratio for ATCO Pipelines of 38%.

CAPP proposed a deferral account to capture volume variances because this was not within ATCO Pipelines' ability to control.

CAPP's expert used the coefficient of variation of return on assets and of return on equity to rank ATCO Pipelines and nine other Canadian utilities from highest risk to lowest risk. Historic data for ATCO Pipelines was available for only two years. For the other utilities up to seven years of historic data was used. ATCO Pipelines' figures were compared using the two years of available data and also using four years of data, which included two years of forecast data. On this basis ATCO Pipelines ranked below average risk. However, CAPP based its analysis on an assumption that ATCO Pipelines was of average risk. CAPP indicated that it conservatively assessed ATCO Pipelines' business risk as medium, that is, higher than the lowest risk pipelines. CAPP indicated that the regulatory climate is stable and predictable and therefore contributes to a low business risk profile, but noted that there are unresolved regulatory issues that will be a major determinant of ATCO Pipelines' competitive risks. CAPP believed that resolution of these issues will lead to lower risks but, for now, conservatively assessed a middle level of risk.

CAPP noted that the average common equity ratio and pre-tax interest coverage ratio, for the Canadian utilities using data provided by ATCO Pipelines' expert, were 37.9% and 2.3 respectively. CAPP calculated that using CAPP's recommended ROE of 9% and using ATCO Pipelines' debt costs and preferred equity component and cost, a common equity ratio of 37.6% was required to achieve an interest coverage ratio of 2.3. On this basis, CAPP's expert found that an appropriate equity ratio for ATCO Pipelines was 38%.

CAPP argued that its expert's risk rankings were based on objective short-term measures of business risk. CAPP indicated that its expert's recommended capital structure was based on a sample of Canadian regulated utilities that had short-term business and equity risks comparable to those of ATCO Pipelines and that have demonstrated financial integrity and ability to access the capital markets. CAPP argued that its expert's objective risk rankings were not nonsensical just because they differed from another expert's subjective rankings.

CAPP assessed overall demand risk as low. It noted that some industrial load was price sensitive, but also noted that ATCO Pipelines served the loads of Edmonton and Calgary, which were two of the fastest growing cities in Canada. CAPP also noted the connection of a new long-term gas-fired generation plant.

CAPP viewed the North as less developed such that there was significant potential for direct connected gas supply in the long-term. CAPP viewed the South as mature but still prolific. CAPP viewed the exchange mechanism and the connection to Alliance to be attractive to producers connecting to APN. CAPP indicated that any decline in direct connected gas could be made up from NGTL supply. CAPP viewed the dual connected customers as assets and noted that ATCO Pipelines has worked hard to increasingly sign-up dually connected load. CAPP did not see contract term as an issue since gas would flow in accordance with supply and demand fundamentals, which were strong. The supply risk related to return of capital through depreciation and was therefore a depreciation issue, and not a capital structure issue. CAPP argued that loss of revenue from receipt points was a toll issue, not a rate of return issue.

CAPP stated that the Board has provided a stable and predictable regulatory climate for the utilities under its jurisdiction and will continue to act in a measured way. It is unreasonable to try to protect against all eventualities in the capital structure. CAPP's expert argued that longer-term or unexpected risks outside of normal fluctuations and utility management's control could be dealt with by the Board through special measures.

CAPP argued that the standalone principle should not allow ATCO Pipelines to target a higher than optimum debt rating just because of its parent's debt rating.

CAPP argued that the bond market has not embraced S&P's downgrades, DBRS has not followed suit, and any downgrade even to a utility could be the result of a downgrade of the parent due to non-regulated activities, since subsidiaries are rated the same as the parent.

Cargill

Cargill supported CAPP's expert's recommendation of a 38% common equity ratio.

Cargill indicated that the Board primarily should be concerned with the risks of under-recovery of capital-related costs over the long term, and secondarily, volatility in year-to-year earnings. Cargill noted that while ATCO Pipelines has higher volatility risk than other major pipelines, and NGTL in particular, this risk was not new and was presumably incorporated in ATCO Pipelines' last determined equity ratio. It is not appropriate to compensate ATCO Pipelines for self-imposed risks including risks associated with lack of a volume deferral account, the Muskeg River "removal" from regulated service, and risks around dually connected customers where ATCO Pipelines was not the first connected and where ATCO Pipelines has provoked retaliation by NGTL.

Cargill argued that CAPP's expert's approach, based on earnings volatility, is more reasonable than the approach of ATCO Pipelines. CAPP's expert's recommendation of 38% is well above the ratios for other pipelines, but is consistent with ATCO Pipelines' small size and its failure to request or accept significant deferral accounts. CAPP's expert's basis for measuring risk was actual variability in return as a %age of assets and an analysis of the probability of inability to service debt costs. In contrast, ATCO Pipelines' expert's evaluation of the relative risks of various utilities was not based on any calculation at all; it was her apparently subjective conclusion based on her consideration of factors that are not described. ATCO Pipelines had not offered any reasons why CAPP's expert's measure of risk was wrong, it only observed that the results differed from other methods.

Cargill argued that ATCO Pipelines needs to show that its overall level of business risk has increased in the recent past in order to justify its requested increases in equity thickness and equity return.

Cargill argued that the primary focus of ATCO Pipelines' business risk discussion is on issues related to toll design, cost allocation and certificate policy. These included competition with NGTL, potential bypass by Alliance and a future Mackenzie valley pipeline, NGTL zero toll and pipeline proliferation policy.

Cargill stated that ATCO Pipelines uses a 100% demand charge approach that insulates it from weather risk and makes it less risky than a conventional gas distribution utility like Enbridge Gas Distribution (EGD). There was no risk that ATCO Gas would terminate its contract with ATCO Pipelines since both are owned by the same parent. Cargill argued that ATCO Pipelines would only have inadequate supply if Alberta end-users are to be deprived of gas supply in the foreseeable future. In practical terms that risk is zero, since Alberta requirements are a small fraction of the total WCSB production and it is reasonable to assume that Alberta consumers and particularly core consumers will be the last to go without gas if and when supply declines dramatically. Alberta consumers will get gas and ATCO Pipelines will deliver it.

Cargill argued that it is doubtful that even the loss of all producer volumes would threaten the financial viability of ATCO Pipelines since costs would pass on to captive customers. The regulatory regime will likely prevent any kind of "death spiral" scenario. Cargill argued that there is no proof that risks of a municipality taking back its franchise has increased. If franchise loss by ATCO Gas occurs, the risk of physical bypass of ATCO Pipelines is very low, as the regulator would likely not allow it. Any lack of ability to attract new supply is irrelevant since the existing pipeline was presumably built to be economic based on existing gas supply.

Cargill argued that ATCO Pipelines will recover its investment through depreciation long before any physical exhaustion of the WCSB. Any loss of supply receipts is a short-term toll design problem that ATCO Pipelines has the ability to address.

Cargill argued that ATCO Pipelines' self-assigned S&P risk profile score of four was unsound and poorly supported.

FGA

FGA argued that there is increased certainty that the Board will resolve some longstanding inter-pipeline competition issues, which should result in a reduction rather than an increase in ATCO Pipelines' supply risk. FGA disagreed with the position that the EDA mechanism and its deficit have added to risk.

IGCAA

IGCAA argued that the Board should award ATCO Pipelines the same equity ratio as for ATCO Gas.

IGCAA argued that the Board's assessment of risks in Decision 2001-97 for APS, resulting in a 45.5% common equity ratio, was correct for the risks at that time and therefore an incremental approach to risk can be used.

IGCAA indicated that WCSB maturity was considered in Decision 2001-97, but IGCAA questioned whether it is a risk given that ATCO Pipelines' rates are designed to recover its investment. If it is a risk, it is not materially different than that considered in Decision 2001-97 given high gas prices, which encourage more drilling. IGCAA believed that ATCO Pipelines' attribution of production declines as the reason for contract terminations at virtually all singly connected producers defied logic, when at the same time ATCO Pipelines attributed the reason for contract terminations at almost all dually connected points to competition. IGCAA argued that a more logical reason for contract terminations at singly connected points is uncertainty over tolls, combined with excess capacity on the system that provides comfort that interruptible service will be available.

IGCAA argued that competitive pressures associated with negative balances in the EDA are fundamentally the same risk that the Board spoke to, and provided compensation for, in Decision 2001-97. The negative balance in the EDA is temporary.

IGCAA argued that ATCO Pipelines' access to export markets has materially improved since 2001. ATCO Pipelines now has capacity to Alliance and TransGas of 275mmcf/d. ATCO Pipelines does not charge a toll other than UFG for deliveries to Alliance and TransGas and thus can avoid paying tolls to NGTL which apply where gas is delivered to another pipeline. In IGCAA's view, NGTL opposed ATCO Pipelines' TransGas contract in this proceeding because it fears loss of revenue on its own system.

IGCAA indicated that the risk of loss of customers was described by ATCO Pipelines as huge in 2001 due to the threat of the Ft. Saskatchewan bypass. For ATCO Pipelines to now claim that this risk has increased since that time is not credible. Unlike the situation in 2001, ATCO Pipelines is not presently facing any competitive NGTL projects. In addition, since the last GRA, ATCO Pipelines has used non-standard contracts to attract significant incremental markets. Given the Fort Saskatchewan decision, ATCO Pipelines is under regulatory protection and its regulatory risk is significantly lower than at the time of the 2001 GRA.

IGCAA argued that the size of ATCO Pipelines is irrelevant and it has proven itself to be a low cost competitor. It also argued that there is no longer a material difference in the business risk faced by ATCO Pipelines and ATCO Gas.

Canadian Forest Oil Ltd. / Producers Marketing Ltd. (ProMark)

ProMark indicated that the risks of dual connected sites should not be recognized as a credible business risk element because the risk was self imposed and was to the benefit of ATCO Pipelines with the costs borne by shippers.

Views of the Board

This section addresses the following four topics:

- Business Risk Definition
- Business Risk Measurement
- The role of U.S. data
- ATCO Pipelines' Business Risk and Appropriate Common Equity Ratio

Business Risk Definition
The Board agrees with Calgary's experts' definition of business risk as the uncertainty attached to return on capital, which is defined as EBIT divided by invested capital. In the Board's view, business risks include both short-term and long-term considerations. In return for investing funds, debt investors require substantial certainty that operating earnings will be available to pay debt interest and principal amounts. EBIT is a measure of the operating earnings generated over a given period of time, and it is subject to uncertainty.

The Board notes ATCO Pipelines' comments regarding longer-term risks of supply variability and franchise loss. The Board also notes Cargill's view that the issue the Board needs to be primarily concerned with is the long run risk of under-recovery of capital-related costs. The Board agrees with CAPP and Cargill that supply risk ultimately relates to return of capital through depreciation and is a depreciation issue. While long-term supply and franchise risks exist, the Board believes that these can be dealt with in future if they materialize. It would not be appropriate to impose the costs of an incrementally higher equity ratio at this time, to protect against these longer-term risks which may not materialize or which can likely be dealt with more appropriately through reallocation of costs or through accelerated depreciation at a future time. The Board agrees with CAPP's expert's argument that longer-term or unexpected risks outside of normal fluctuations and utility management's control could potentially be dealt with by the Board through special measures. Therefore, the Board will focus on shorter-term business risks consistent with normal expected fluctuations in return. The Board will also consider business risks as perceived by the capital markets.

Business Risk Measurement
The Board considers that volatility in historic return on capital is a direct measure of realized historic business risk. And given relative stability in the equity ratio and interest costs, variation in historic realized return on equity is also a reasonable, although indirect, measure of realized historic business risks. The Board believes that CAPP's expert's use of the coefficient of variation of the return on assets and of return on equity as measures of business risk has merit. The Board agrees with Calgary that historic deviations between approved and achieved returns on capital and equity are a direct measure of realized historic business risk. However, the Board views all these historic measures as incomplete, in that risks that are present but which have not materialized are not reflected in the historic volatility numbers. In addition, there may be some shortcomings in CAPP's calculations given that only two years' actual historic data was available for ATCO Pipelines. In addition, CAPP's use of income before extraordinary items may have masked actual volatility in earnings and distorted the rankings.

Prospective business risks are inherently difficult to measure and difficult to translate into an appropriate equity ratio. A common method is to set the equity ratio at a level similar to the

actual (as opposed to awarded) equity ratios of comparable regulated utilities that have acceptable credit ratings and acceptable current debt yields. Adjustments can be made for any perceived incremental difference in business risk between the comparable companies and the subject utility. Although the comparisons and the adjustments are somewhat subjective, the Board views this as a reasonable method. Another method is to use the previously approved equity ratio as a starting point and adjust for any substantial changes in business risk. The Board views this as a reasonable method, although it is less applicable when the changes in business risk are very substantial, such as might be caused by industry restructuring. ATCO Pipelines has proposed the use of S&P guidelines to determine the appropriate equity ratio. Comparable companies that have been assigned an S&P risk score can be used to estimate an S&P risk score for the subject utility, where S&P has not directly provided one. S&P then provides guideline equity ratios for various risk scores and credit ratings. The Board sees some merit in this procedure, but has several concerns including the reliance on a single debt rating agency, the small number of Canadian utilities that have been assigned a risk score by S&P to date, the subjectivity involved, and the interveners' arguments that S&P scores and guidelines are not fully reflected in actual debt ratings of either S&P or in the market debt yields.

The Role of U.S. Data

The Board notes Calgary's comments on the differences in the use of deferral accounts between the U.S. and Canada. The Board also notes ATCO Pipelines' comments regarding the lack of highly rated Canadian utilities and the need to recognize that S&P is globally harmonizing its debt ratings.

The Board agrees with interveners that Canadian comparable regulated utilities are more likely to reflect Canadian market requirements and regulatory conditions than is U.S. data. Therefore the Board has not placed significant weight on U.S. data or comparisons.

ATCO Pipelines' Business Risks and Appropriate Common Equity Ratio

The Board notes that interveners recommended a common equity ratio of 38% to 42%, while ATCO Pipelines recommended a common equity ratio of 50%.

Regarding the use of comparable Canadian regulated companies to determine the equity ratio, the Board notes that the three major Canadian pipelines identified in ATCO Pipelines' expert's Schedule 2, are clearly of substantially lower business risk than ATCO Pipelines. Due to the fact that most regulated utilities are not subject to the level of competition that ATCO Pipelines faces, it is difficult to identify comparable Canadian regulated utilities in this case. However, the experts did rank ATCO Pipelines' risks in comparison to various utility industry segments.

ATCO Pipelines indicated that it was riskier than an average Canadian regulated utility and similar in business risk to Nova Scotia Power.

Calgary argued that ATCO Pipelines was less risky than oil pipelines, less risky than PNG, and more risky than the overall average of gas pipelines.

The Board notes that data provided by Calgary indicates that the actual common equity ratios of the gas utilities ranged from 31.5% to 38.3%. This excluded PNG which had unusual problems and Centra Manitoba which had a government guarantee of its debt. The major gas transmission pipelines had equity ratios in the range of 30-33% and the electric companies had equity ratios in the 35-45% range. The most common debt rating was A.

ATCO Pipelines also provided equity ratios for Canadian utilities, dated 2001. Excluding short-term debt the average gas distribution common equity was 39.1% and the average electric distribution utility common equity ratio was 41.6%. Nova Scotia Power's common equity ratio was 38.4% with a 10.2% preferred component. The Board also notes that Nova Scotia Power's debt ratings by two debt rating agencies were BBB+ and A (low) which is materially below the level of CUL.

The Board agrees with Calgary that ATCO Pipelines is riskier than an average gas pipeline and agrees with ATCO that it is riskier than an average Canadian utility. In the Board's view the comparable company data indicate that the appropriate common equity ratio is in the range of 39% to 45%. The Board is of the view that the assignment of an equity ratio based on comparable company data requires an element of judgement, particularly due to the relatively unique nature of ATCO Pipelines.

The Board notes that the previously approved equity ratio for APS was 45.5% in Decision 2001-97. The Board has not previously determined an equity ratio for APN other than as part of a larger entity. The Board notes that longer-term risks may have increased since the time of that decision. However, as noted above, the Board believes that it is premature to deal with longer-term supply and franchise risks that may or may not materialize and that are best dealt with by changes in the depreciation rate and/or by other measures as appropriate in future. The Board considers that risks to industrial load for APN have declined since Decision 2002-58.[34] Therefore, the Board is not convinced that short-term business risks have increased since the previous decision.

The Board notes ATCO Pipelines' argument that an analysis based on the S&P business scores results in a required equity ratio of 50%. However, as noted above, the Board has several concerns with this method.

The Board notes that ATCO Pipelines forecast a 2003 actual equity ratio of 44.7% for APN and 48.4% for APS, while requesting a deemed equity level of 50%. ATCO Pipelines forecast that the actual equity ratio would reach the proposed deemed level of 50.0% in 2004.

In the Board's view, consideration of the actual equity ratios and actual debt ratings of comparable Canadian regulated utilities provides one of the stronger indications of an appropriate equity ratio, despite a lack of purely direct comparables in that process. In addition, the Board believes it appropriate to consider the previously awarded equity ratio along with incremental changes in risks, in the interests of stability. In reviewing all of the evidence and considerations, the Board finds that a common equity ratio of 43.5% is appropriate for 2003. The Board notes that this will result in a total equity component of approximately 49.5%, consisting of 43.5% common equity and 6% preferred equity.

Therefore, the Board directs ATCO Pipelines to reflect a common equity ratio of 43.5% for both APN and APS in its Refiling for 2003 and to use 43.5% as a placeholder figure for 2004, pending a determination for that year in the Generic Cost of Capital proceeding.

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34 Decision 2002-58 Nova Gas Transmission Ltd., Application to Construct Fort Saskatchewan Extension and Scotford, Josephburg and Astotin Meter Stations

4 REVENUE REQUIREMENT

ATCO Pipelines forecast that Operating and Maintenance (O & M) expenses in the amounts of $47,961,000 in 2003 and $50,418,000 for 2004 in comparison to an estimated $29,010,000 for 2002. The forecasts were based upon an inflation factor or 4% for labor and supplies.

ATCO Pipelines' O & M expenses were segmented into Transmission, and Administration and General expenses.

Table 21. ATCO Pipelines Total O&M Expense ($000)

Line		2001 Actual	2002 Actual	2003 Forecast	2004 Forecast
1	Transmission	17,362	16,280	32,698	35,333
2	Administration & General	15,066	13,477	16,669	16,509
3	O & M Corporate	32,698	29,757	49,367	51,842
4	Less: Non-Utility O & M	1,432	2,016	1,406	1,424
5	O & M Utility	31,266	27,741	47,961	50,418
6	Percent Change		-11.3%	72.9%	5.1%

Key expenditures forecast for 2003 included Muskeg River ($1,658,000), North Minimum Annual Volume charges ($7,424,000), South Minimum Annual Volume charges ($2,555,000) and a one-time Exchange Deferred Account adjustment of $2,458,000.

4.1 Transmission Labour and Supplies Inflation Forecast and Expenses

This section addresses the determination of an appropriate inflation factor to be applied to transmission labour and supplies expenses for 2003 and 2004. Interveners have taken issue with ATCO Pipelines' 4% inflation factor.

Views of the Applicant

ATCO Pipelines used a 4% inflation factor based on management's general knowledge, publicly available information, and expected market conditions in the service area. ATCO Pipelines argued that the only relevant, valid and tested evidence on the record related to Alberta inflation, which at the time of the Application was 7.6 % for Edmonton and 6.4 % for Calgary. ATCO Pipelines stated that it felt it unlikely that the 8 or 9% inflation factors that were being reported at the time would be sustainable, particularly with rising interest rates. ATCO Pipelines argued that the 4% inflation rate used was on the low end of what inflation was expected to be. The witness for ATCO Pipelines noted that ATCO Pipelines relied quite heavily on Bank of Canada reports. However, he acknowledged that the information related to historical data and did not include a forecast of inflation.[35]

ATCO Pipelines noted that in Section 4.1.2 of their Argument AUMA/EDM/CG stated "no rates were supplied nor was an explanation given as to how the information was used by ATCO Pipelines to arrive at a 4% inflation factor".[36] ATCO Pipelines argued this statement was incorrect and noted that ATCO Pipelines had relied on: the Statistics Canada Consumer Price

35 Tr., p. 49 and 1073
36 AUMA/EDM/CG Argument, p. 82

Index (CPI) for Alberta for November and December of 2002, together with the Bank of Canada monetary policy report of October 2002, and the labour settlement for the ATCO Pipelines Employees Association for 2003. ATCO Pipelines further commented that it had indeed provided specific inflation rates of 8% and 9%, 7.6% for Edmonton, and 6.4% for Calgary. ATCO Pipelines also noted that the 2003 labour settlement included a 3.46% cost increase, which relied on these rates as well as the tightening of the proposed Bank of Canada monetary policy to reduce inflation expectations to the 4% level.

Views of the Interveners

Calgary

Calgary did not accept the 4% inflation proposed by ATCO Pipelines as being appropriate because detailed information was provided as to how it was calculated. Calgary stated that in its own calculations of transmission expenses, it had not included items such as the Muskeg River amounts and the NGTL Minimum Annual Volume (MAV) amounts, both of which were essentially placeholders. Calgary argued the amount for the supply portion of transmission expense for 2003 should be $2.019 million for APS, exclusive of the MAV and affiliate costs. For APN the 2003 amount, again exclusive of MAV and affiliate costs, would be $6.254 million. For 2004 the amounts would be $2.161 million for APS and $5.131 million for APN, again exclusive of MAV and affiliate costs.[37]

AUMA/EDM/CG

AUMA/EDM/CG did not support the 4% inflation factor proposed by ATCO Pipelines for either labour or supplies.

AUMA/EDM/CG supported the O&M analysis of Calgary with further adjustments to recognize inflation and a further factor to support the other adjustments recommended by Calgary. AUMA/EDM/CG also submitted the inflation factor should be broken down between Labour and Other (consistent with the ATCO Electric Ltd. application). AUMA/EDM/CG recommended an inflation factor of 3% for Labour and 2% for Other (supplies) for each of the two test years.

By applying this factor to Calgary's tables and using a "weighted factor" of approximately 2/3 supplies and 1/3 labour, AUMA/EDM/CG arrived at an overall inflation factor of 2.33% (where required) for each of the test years, resulting in further reductions of approximately $300,000 - $500,000 in 2003 and $400,000 - $1,000,000 in 2004.

AUMA/EDM/CG stated that the information ATCO Pipelines relied upon in arriving at its inflation factor was less than comprehensive and did not, in any event, support the 4% inflation factor used by ATCO Pipelines. AUMA/EDM/CG stated that no evidence was provided by Mr. Wright for ATCO Pipelines to support his claim that "...the Alberta rate continues to be much higher than the average Canadian rate." During the hearing, Mr. Wright was questioned by AUMA/EDM/CG regarding the Conference Board of Canada forecast inflation rates. AUMA/EDM/CG noted that the Conference Board of Canada was forecasting CPI increases of 2.8% and 2.7% for 2003 and 2004, respectively.[38]

[37] Calgary Argument, p. 69
[38] Tr., p. 1076

AUMA/EDM/CG stated that ATCO relied on information that did not include forecasts of inflation (with the possible exception of comments by the Bank of Canada regarding target inflation levels for 2003). It also stated that none of the information sources for inflation considered "supplies" separately.

Views of the Board

The Board agrees with AUMA/EDM/CG that ATCO Pipelines did not provide a detailed analysis showing how the 4% inflation factor was calculated, and that ATCO Pipelines did not provide any evidence that the company had considered forecasts of inflation, with the possible exception of comments by the Bank of Canada regarding target inflation levels for 2003.

The Board notes that AUMA/EDM/CG's proposal of 3% for labour and 2% for other (supplies), with a total inflation factor of 2.33% is not substantially out of line with the Conference Board of Canada Consumer Price Index forecasts of 2.8% for 2003 and 2.7% for 2004. However, the Board notes that these numbers do not include a consideration of Alberta specific information. In addition, the CPI data is not necessarily an appropriate determinant of inflation in the industrial sector, given the different types of products involved. For these reasons, the Board is concerned that these CPI forecasts may be somewhat low.

Accordingly, the Board will calculate a rate for labour and supplies inflation based on the evidence on the record. For labour, the Board considers that the inflation rate of 3.46 % in ATCO Pipelines' 2003 wage settlement agreement is an appropriate rate to be used as it represents the amount ATCO Pipelines agreed to with its employees. For ease of calculation, the Board will round this rate up to 3.5%. In the absence of any compelling alternative inflation factor for labour for 2004, the Board will also apply 3.5% inflation to labour for 2004.

For supplies, AUMA/EDM/CG recommended a rate of 2% for both 2003 and 2004. By contrast, ATCO Pipelines recommended 4% for both test years. As the Board considers that neither 2% nor 4% are solidly supported by forecasts from reliable sources, the Board considers it appropriate in this case to select the midpoint between these two proposed rates of 3.0% for supplies.

Next, the Board agrees with ATCO Pipelines that a single rate for both transmission labour and supplies is appropriate. Accordingly, the Board will create a blended rate based on the fact that labour expenses accounted for approximately 30% of O&M expenses, while supplies accounted for the remaining 70%[39]. This is similar to the approach proposed by AUMA/EDM/CG. Thus, by using a weighted average of labour and supplies, a blended rate of inflation of 3.15% is derived for both transmission labour and supplies for 2003 and 2004.

Accordingly, the Board directs ATCO Pipelines, in its Refiling, to recalculate transmission labour and supplies expenses for both 2003 and 2004 using an inflation rate of 3.15%.

The Board also directs ATCO Pipelines to file, in future GRA applications, more detailed information supporting its inflation factors.

39 Ratio obtained from labour to supplies forecast expenses for 2003 from the Application and Attachment CAL-AP-128 (e).

4.2 Full Time Equivalent (FTE) Staff

Views of the Applicant

ATCO Pipelines' requirement for 14 additional FTEs in 2003 and three additional FTEs in 2004 accounted for labour cost increases of $2,079,000 and $1,099,000 for 2003 and 2004 respectively. In ATCO Pipelines' view, its requirement for additional staff was justified by a combination of business factors, including:

- Higher costs for more stringent and timely customer account balancing;
- Higher operating costs for measurement of SCADA maintenance and inspection;
- Higher planning, system optimization and gas control costs associated with overall system balancing and line pack management;
- The full year impact for operation of the Lodgepole compressor;
- Higher operations costs for measurement maintenance and inspection for UFG meters in the north;
- The proposed implementation of Intra-Alberta delivery increased Minimum Annual Variance (MAV) charges by NGTL;
- Inflation;
- The reallocation of ATCO Group costs from the South based on updated allocation of higher I-Tek costs;
- Higher I-Tek costs due to higher activity levels;
- Hearing expenses and increases to the reserve for injuries and damages due to higher insurance deductibles;
- Higher insurance costs, legal fees and temporary accounting contractors; and
- Higher insurance and fringe benefit expenses.[40]

ATCO Pipelines stated that, as a result of such factors, additional resources were required, resulting in an increase in FTEs from an estimated 246.5 in 2002, to 260.5 in 2003 and 263.5 in 2004. The table below summarizes the proposed increases as requested by ATCO Pipelines for each department of the company.[41]

Table 22. Breakdown of FTEs for Departments of ATCO Pipelines From 2001 to 2004

	2001 Actual FTE		2002 Estimate FTE		2003 Forecast FTE		2004 Forecast FTE	
	Change	Year End	Change	Year End	Change	Year End	Change	Year End
Department								
Commercial & Finance	8.0	45.7	2.0	47.7	9.0	56.7	1.0	57.7
Business Development	1.0	43.0	2.0	45.0	2.0	47	-	47.0
Operations	9.0	154.0	(3.2)	150.8	3.0	153.8	2.0	155.8
Regulatory	-	3.0	-	3.0	-	3.0	-	3.0
Total Company	**18.0**	**245.7**	**0.8**	**246.5**	**14.0**	**260.5**	**3.0**	**263.5**

40 Pages 8, 10, 13, 17 of 19 in Section 4.2 of the Application.
41 Extract from Attachment CAL-AP-128 (e).

ATCO Pipelines stated that Calgary incorrectly established the FTEs in its evidence.[42] It further stated that Calgary was incorrect in arguing that there was no demonstrated increase in activity to justify the forecast increase in full time equivalent employee positions.[43] ATCO Pipelines was also of the opinion that Calgary compromised its analysis by using FTEs that had not been adjusted for variations in capital programs versus O&M and with no adjustment made for temporaries or contractor differences.

Views of the Interveners

Calgary

Calgary was opposed to the proposed FTE increases for 2003 and 2004 as proposed by ATCO Pipelines. It stated that ATCO Pipelines did not make a good case for why 14 additional FTEs were required in 2003 and a further three were required in 2004, particularly given that there was no demonstrated significant increase in activity.

In its Further Evidence, Calgary made note of numerous variances in ATCO Pipelines' labour costs.[44] First, APS was able to reduce its labour cost in 2002 from 2001; that is the labour costs for APS declined by $90,000 or 3.3% between 2001 and the 2002 actual. Second, the actual 2002 labour costs were 15.7% less than the forecast prepared by APS in the 2001-02 GRA filing. Furthermore, ATCO Pipelines' forecast for 2002 included in the 2003-04 GRA Application is $2,824,000 or 7.4% higher than actual 2002 even though the forecast was prepared when at least 8 or 9 months data was known.

By comparing the actual 2002 APS labour cost to the forecast 2003 cost, Calgary noted an increase of 29.4%. For the two-year period actual 2002 to the forecast 2004 the increase observed was 35.2%. Calgary stated that there was no relationship between ATCO Pipelines' 4% inflation and the actual increase being requested.

In its Further Evidence, Calgary noted a similar pattern for APN; that is APN was able to reduce its 2002 labour cost from 2001 by 1.9%. After adjusting for Muskeg River, the forecast for 2002 included in the Application showed labcur cost as being 9.1% greater than the actual for 2002. Furthermore, the forecast 2003 labour costs were 27.8% higher than the actual 2002 and 34.9% in 2004 when compared to the actual 2002. By examining tables 4.2-8, 4.2.5 and 4.2.2 of the Application, Calgary stated that ATCO Pipelines' increase of 14 FTEs for 2003 and three for 2004 would result in a $/FTE labour cost of $39,854 for 2003 and $41,450 for 2004.[45]

Calgary recommended the following increase in labour costs associated with the increase in FTEs proposed by ATCO Pipelines:

Table 23. Calgary's Recommendation for Increase in Labour Costs Associated with FTEs

	Total Cost	$/FTE
2003	$9,620,000	$39,854
2004	$10,120,000	$41,450

42 ATCO Pipelines Argument, p. 56
43 ATCO Pipelines Reply Argument, p. 77
44 Table 2 in Calgary's Further Evidence
45 See Exhibit 9-12, Calgary's Evidence of June 2, 2003

With respect to supplies, Calgary made note of numerous variances in ATCO Pipelines' supplies costs. Calgary noted that APS was able to reduce its supplies expenses in 2002 from 2001; that is the supplies expenses for APS declined by 10.2% between actual 2001 and 2002. Furthermore, Calgary noted that the forecast 2002 supplies cost included in the Application was 1.3% higher than the 2002 actual amount. After adjusting for Muskeg River, supplies costs for the 2003 forecast were 31.4% higher than the 2002 actual. It also noted that the 2004 forecast showed a 1.9% reduction from the 2002 actual based on the Muskeg River adjustment. Calgary further stated that using the forecast for 2002, 2003 supplies costs were 29.6% higher, and that 2004 showed a reduction of 3.1% based upon the Muskeg River and the MAV adjustments. Thus, based upon FTEs, forecast 2002 supplies cost declined by 9.3% per FTE from the 2001 actual. However, 2003 forecast supplies cost were 22.6% higher than the 2002 forecast per FTE. Calgary therefore, recommended that Supplies expenses for 2003 be limited to no more than $8,277,000 for 2003, and $7,292,000 (exclusive of the NGTL placeholders for MAV) for 2004.

Views of the Board

It is well established that a public utility such as ATCO Pipelines bears the onus of establishing that any proposed increases in expenditures are just and reasonable. In this case, the Board agrees with Calgary that ATCO Pipelines has not adequately justified its requirement for 14 new FTEs in 2003 and 3 new FTEs in 2004, for the reasons outlined below.

In the Revenue Section 7, ATCO Pipelines forecasted a decline in demand and throughput, and has forecast a small volume of new contract demand to replace a signification reduction in demand from existing contracts. Declines in both demand and throughput would not tend to support an increase in FTEs. The Board has considered the business factors cited by ATCO Pipelines in support of its required increase in FTEs of 14 for 2003 and 3 for 2004. However, the Board finds the business factors cited to be too general in nature to provide a reliable basis for the proposed FTE increases. In the Board's view, ATCO Pipelines has not met the onus it bears to justify these increases because it has not, to the Board's satisfaction, quantified the labour component associated with these business factors to show specifically why 14 and 3 additional FTEs are required in the respective test years. Furthermore, the Board notes that ATCO Pipelines has not included the impact of a vacancy rate in its FTE filings, even though the Board considers it likely that some positions would be vacant at any one time.

The Board directs ATCO Pipelines, in the next GRA, to identify its forecast of vacancies in FTEs including annualization of new FTEs.

Taking into account the forecast decline in demand and throughput, as well as the fact that ATCO Pipelines has neither supported its requirement for 14 additional FTEs in 2003 and 3 in 2004 by quantifiable factors, nor taken a reasonable vacancy rate into account, the Board is not persuaded that it is reasonable for customers to bear the full cost of ATCO Pipelines' proposed FTE increases. Nevertheless, the Board considers that at least some of the business factors listed by ATCO Pipelines, such as additional requirements for customer account balancing, operation and maintenance of SCADA, and UFG meter measurement, maintenance and inspection, could reasonably result in a requirement for additional FTEs in the two test years.

The Board notes that in the AltaLink Decision 2003-061, the Board found that the applicant had not met its onus of proving why the number of requested new FTEs were justified for the test period. In that case, the Board considered that an award of 50% of the FTEs requested was

warranted. The Board believes that it must also apply its judgement in the present case given inadequate justification of the number of new FTEs by the Applicant.

The Board notes Calgary's evidence that the Applicant's actual 2002 labour costs were 15.7% less than the forecast prepared by APS in the 2001/2002 GRA filing, and further, that comparing the actual 2002 APS labour cost to the forecast 2003 cost shows an increase of 29.4%. For the two-year period actual 2002 to the forecast 2004, the increase observed by Calgary was 35.2%. The Board agrees with Calgary that there was no relationship between ATCO Pipelines' 4% inflation and the actual increase in labour costs being requested, and further considers that a significant adjustment to the number of forecast FTEs would appear to be warranted.

Even though the Board believes ATCO Pipelines reasonably requires at least some new FTEs, the Board does not consider that awarding even 50% of the requested number would be reasonable in these circumstances. Given the lack of a reasonable filed vacancy rate, the Board considers the number of FTEs should be lower than 50% of the 14 requested in 2003, and approximately 50% of the 3 requested in 2004. Considering all the foregoing reasons, and applying its own experience to the evidence in light of those reasons, the Board finds that it would be just and reasonable to approve an increase of five FTEs for 2003 and two FTEs for 2004.

The Boar directs ATCO Pipelines, in its Refiling, to recalculate the costs associated with an increase in FTEs of five for 2003 and two for 2004, and to show the corresponding reduction in costs from the original filing of 14 FTEs in 2003 and three FTEs in 2004.

4.3 Administration & General (A&G) Labour and Supplies Inflation Forecast and Expenses

This section addresses the determination of an appropriate inflation factor to be used for administrative and general labour and supplies expenses for 2003 and 2004.

Views of the Applicant

With respect to costs for administrative and general labour and supplies, ATCO Pipelines again used 4% as the inflation factor, for the same reasons indicated above with respect to transmission labour and supplies. Again, ATCO Pipelines argued that the forecast inflation rate of 4% was conservative and reasonable.[46] ATCO Pipelines stated that the inflation factor was based on management's general knowledge, taken from publicly available information, including government published reports, and expected market conditions in the service area. ATCO Pipelines felt it was unlikely that the 8 or 9% inflation factors that were being reported at the time would be sustainable, particularly with rising interest rates.

ATCO Pipelines argued that Calgary did not adjust for one-time costs that distort year-to-year comparisons. ATCO Pipelines stated that by not factoring out significant changes in regulatory accounts or considering the changes to the insurance industry post September 11, 2001, Calgary had made its analysis of year-to-year cost levels of no value.[47] ATCO Pipelines argued that the only relevant, valid and tested evidence on the record related to Alberta inflation, which at the

[46] ATCO Pipelines Argument, p. 55
[47] ATCO Pipelines Reply Argument, p. 78

time of the Application was 7.6% for Edmonton and 6.4% for Calgary. ATCO Pipelines argued that the 4% inflation rate used was on the low end of what inflation was expected to be.

Views of the Interveners

Calgary

In Table 2 of its Further Evidence, Calgary noted that the forecast 2002 A&G cost was reduced by 13.5% from the 2001 actual to the 2002 actual. Furthermore, it noted that A&G costs for the 2003 forecast increased by 22.0% per FTE over the 2002 forecast, and by 19.3% per FTE for the two-year period from the 2002 forecast to the 2004 forecast. Calgary emphasized that there was no relationship between these numbers and the 4% contained in the Application. Thus, Calgary recommended that the total A&G expenses for 2003 be no more than $13.005 million (based on the 2002 forecast costs per forecast FTE increased by 4% inflation and then adjusted for the forecast number of FTEs in 2003 and 2004) and no more than $13.681 million in 2004, including Affiliate and regulatory accounts. Using the methodology in Table 2 of Exhibit 9-12, the A&G, including Affiliate costs and regulatory accounts for APS in 2003 would be $5.260 million and $5.534 million in 2004. Again, using the methodology in Table 2 of Exhibit 9-12, the A&G for APN including Affiliate costs and regulatory accounts would be $7.745 million in 2003 and $8.147 million in 2004.

Views of the Board

The Board notes that ATCO Pipelines used the same inflation rate of 4% for both Transmission Labour and Supplies and A&G Labour and Supplies. Again, the Board notes that ATCO Pipelines did not provide a detailed analysis showing how the 4% inflation rate was calculated, and that ATCO Pipelines did not provide any evidence that the company had considered forecasts of inflation, with the possible exception of comments by the Bank of Canada regarding target inflation levels for 2003.

However, interveners did not propose an alternative to the 4% inflation rate proposed by ATCO Pipelines. The Board does not consider Calgary's proposals to reduce the amounts for A&G to be adequately supported.

As indicated in relation to Transmission Labour and Supplies, the Board has concerns with the 4% rate for inflation proposed by ATCO Pipelines, yet no alternative rate was proposed by interveners specifically for A&G. The Board agrees with ATCO Pipelines, however, that it is appropriate for the same inflation rate to apply to both A&G and Transmission. Accordingly, the Board approves the same blended 3.15% inflation rate to A&G labour and supplies as approved earlier in Section 4.1.1 for Transmission Labour and Supplies.

Accordingly, the Board directs ATCO Pipelines to recalculate, in its Refiling of evidence, A&G labour and supplies expenses for both 2003 and 2004 using an inflation rate of 3.15% and to provide details showing the reduced costs.

4.4 Pension and Post Employment Expense

Background

In Decision 2001-105,[48] the Board approved the Negotiated Settlement for Pensions between ATCO Gas, Pipelines and Electric (ATCO Companies) and their customers (Pension Settlement). As a result of that Settlement, ATCO has recognized pension and other post employment expenses on a cash basis, effective as of the year 2000. The Board notes that neither the Pension Settlement, nor Decision 2001-105, dealt with the Deferred Pension balances.

Views of the Applicant

ATCO Pipelines provided the Deferred Pension balances to December 31, 1999 in a continuity schedule in response to CG.AP-45(a).

Table 24. ATCO Pipelines – Deferred Pension Continuity ($000)

	North	South	Total
Deferred Pension (Dec. 31/98)	852	866	1,718
Pension Expense	(121)	(59)	(180)
Pension Funding	181	88	269
Pension Gain	1,199	1,199	2,398
Deferred Pension (Dec. 31/99)	2,111	2,094	4,205

Views of the Interveners

AUMA/EDM/CG submitted that it was appropriate to use part of the $423,470,000 funding excess,[49] exceeding the prescribed limit under the income tax act by $334,432,400, to cover the money purchase or supplemental pension employer deposit requirement for the test years. AUMA/EDM/CG noted that this was the suggestion of the ATCO Pipelines' actuarial consultant.

AUMA/EDM/CG also submitted that ATCO Pipelines should be directed to file the details for all retirees from regulated companies, noting the number of years worked in the regulated companies and total number of years worked. AUMA/EDM/CG argued that this was necessary to avoid non-utility personnel being transferred to utilities for pension purposes.

AUMA/EDM/CG were also concerned with the balance of the Deferred Pension account. Rather than decreasing, the balance appears to be set at $4,205,000. At issue was that ATCO Pipelines is receiving an effective weighted cost of capital return plus a gross up for income taxes on the account balance, while the estimated return in the pension plan is only 7%. Also, the account balance is not being amortized against reduced contribution requirements for the defined pension plan because of the surplus. AUMA/EDM/CG submitted it would be reasonable for the balance of the Deferred Pension to receive the return estimated for the defined benefit pension plan.

In addition to the above, AUMA/EDM/CG submitted that the $2.398 million gain flowing from restructuring would never be received by customers to offset the costs paid for restructuring. In AUMA/EDM/CG's view, the gain would remain in the pension plan and not appear as a credit to

48 Decision 2001-105 – ATCO Electric Ltd., ATCO Gas and Pipelines Ltd., and Northwestern Utilities Limited (ATCO Companies), Pension Filing – Negotiated Settlement, dated December 31, 2001

49 MERCER Actuarial Valuation for Funding Purposes as at Dec 31, 2001 ATCO Gas GRA CG-AG-84(a)

the Deferred Pension account whereas ATCO always maintained the pension gain would offset restructuring costs. AUMA/EDM/CG submitted if the $2.398 million gain being carried in the Pension Deferral account could not be satisfied by a transfer of assets from the defined pension plan, it should be removed from the deferral account. Alternatively, if not removed, it should not attract any return. Finally, AUMA/EDM/CG argued that the return associated with this gain since 1999 should be refunded to customers.

AUMA/EDM/CG noted that in EUB Decision 2001-105 it was agreed that the ATCO Companies Deferred Pension Balances existing at January 1, 2000, would be dealt with in future regulatory proceedings.

Views of the Board

The Board agrees with AUMA/EDM/CG that customers have over-funded the defined pension plan and that use of the funding excesses to cover other pension requirements would be appropriate. The Board therefore directs ATCO Pipelines to use the funding excess ($423.47 million) to cover its money purchase and supplemental pension deposit requirements for the test years.

The Board also agrees with AUMA/EDM/CG that more detailed information is needed from ATCO Pipelines in order to be certain that customers are not harmed by the above policy, given the possibility that an employee working in non-regulated activities might transfer to regulated operations shortly before retirement. The Board considers that it would not be an onerous task for the Company to provide at the next GRA, a list of retirees, without identifying the names, showing years of service for pension purposes in both regulated and un-regulated positions.

Accordingly, the Board directs ATCO Pipelines in future GRAs, to provide details of all retirements from regulated operations since the preceding GRA, specifying years worked in regulated and non regulated divisions, the related chronology and the total number of years of employment used for pension purposes. Furthermore, for the purposes of completion of the record, ATCO Pipelines is directed, in its Refiling, to complete the Deferred Pension Continuity schedule, shown above, to include amounts for the years 2000 to 2004 inclusive.

With respect to the $2.398 million gain included in the Pension Deferral Account, the Board notes the concern of the CG that if the gain could not be satisfied by a transfer of assets from the defined pension plan, it should be removed from the deferral account. The Board notes AUMA/EDM/CG's comment that, if the gain is not removed, it should not attract any return, and that the return associated with this gain since 1999 should be refunded to customers. There appears to the Board to be some merit in this view.

The Board acknowledges that the deferred pension balance has been carried in NWC in the amount of $4.205 million since 2001, consistent with the terms of Decision 2001-105, which approved the Pension Settlement. The Board notes the following from Clause 7 of the Settlement states:

> The ATCO Companies will use the cash basis of accounting for all pension costs, effective January 1, 2000 for purposes of utility revenue requirements. Related Canadian Utilities Limited charges will be accounted for on the same cash basis. The ATCO Companies' Deferred Pension Balances existing at January 1, 2000 (refer to Schedule 1) will be dealt with in future regulatory proceedings.

The Board notes that the Settlement was silent on the administration of the resultant ATCO Deferred Pension balances, other than that they would be dealt with in future regulatory processes. The Board also notes that ATCO Pipelines has presented no proposal for resolution of this issue in the present Application.

The Board directs ATCO Pipelines to re-examine the treatment of the Deferred Pension balance in the next GRA and provide a detailed explanation and rationale for treatment of the gain in the Pension Deferral Account.

It would be helpful to the Board if this assessment included the following:

- The conceptual methodology that was utilized to determine the amount of any surplus in the fund (for example, was present value, future value or some other process utilized, and all assumptions).
- Quantification of the factors that led to the surplus in the pension fund (for example, downsizing, changes related to the switch to a defined contribution, excessive past funding rates, the assumed and actual investment gains/losses, etc.).
- An explanation of how customers received the benefits of the surplus when it is equally plausible that the pension asset was simply the result of over funding.

4.5 Regulatory Reserve Account

Background

ATCO Pipelines provided the Hearing Cost Deferral Account balances in a continuity schedule,[50] as follows.

Table 25. Hearing Cost Deferral Account

	Actual			Forecast	
	2000	2001	2002	2003	2004
Opening Balance	313	634	(732)	(421)	(49)
Expense	372	(1,739)	(500)	(378)	(701)
Assessment	(51)	373	811	750	750
Closing Balance	634	(732)	(421)	(49)	0

Views of the Applicant

ATCO Pipelines submitted that its forecast of expenses was not seriously challenged by interveners, and that its forecast should be approved as filed.

ATCO Pipelines countered the AUMA/EDM/CG proposal that the 2003 payment should be set to zero. ATCO Pipelines argued that, to be consistent with prospective rate-making principles, the forecast should not be altered.

[50] CG.AP-44

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG noted that ATCO Pipelines had confirmed in testimony[51] that the $750,000 assessment for 2003 was for hearing costs for the Phase I hearing, and would not likely be spent during 2003. AUMA/EDM/CG argued that the payment for 2003 should be reduced to zero, allowing the closing balance for 2003 to be adjusted to $701,000.

Views of the Board

ATCO Pipelines argued that altering forecasts used in the preparation of a regulatory filing may damage the prospective nature of the rate making process. However, as all parties are aware, the time lapse between the filing of any original evidence and the time of the subsequent hearing can be several months during which time certain costs or parameters can change markedly. In the past, the Board has taken into account current or updated information on actual costs in cases where the updated information is materially different from the forecast information presented in the Application. In the Board's view, this practice is supported, in part, by Section 91 of the Public Utilities Board Act and is consistent with the approach it took most recently in relation to the ATCO Electric Ltd. 2003-2004 GTA in Decision 2003-071[52] and the ATCO Gas 2003-2004 GRA in Decision 2003-072.[53]

In this instance the Board agrees with AUMA/EDM/CG that the $750,000 assessment for hearing costs for Phase I of the hearing will likely not be paid in 2003. The Board considers $750,000 to be material for a utility the size of ATCO Pipelines and therefore, in this case, it is appropriate for the Board to adjust the mid-year working capital for 2003 and 2004 in accordance with the more up to date information received at the hearing respecting the likely timing of the payment of hearing costs for the ATCO Pipelines Phase I GRA.

Accordingly, the Board directs ATCO Pipelines to reduce the assessment to the Hearing Cost Reserve account for 2003 to zero, allowing the closing balance for 2003 to be adjusted to $799,000, and adding $750,000 to the assessment for 2004. The Board also directs ATCO Pipelines to recalculate its 2003 and 2004 midyear Necessary Working Capital in accordance with this change.

4.6 Reserve for Injuries and Damages

Background

ATCO Pipelines provided the Reserve for Injuries and Damages (RID) balances in continuity schedules, as follows.

[51] Tr. pp. 115 - 117

[52] Decision 2003-071, ATCO Electric Ltd., 2003-2004 General Tariff Application, Rate Case Deferrals Application, 2001 Deferral Application (October 2, 2003), pp. 110-111

[53] Decision 2003-072, ATCO Gas, 2003-2004 General Rate Application, Phase I (October 1, 2003), pp. 20-22

Table 26. North Reserve for Injuries and Damages ($000)

	2001	2002	2003	2004
	Actual	Estimate	Forecast	Forecast
Opening Balance	703	610	518	500
Provision	(94)	(94)	(1,268)	(250)
Payments	1	2	250	250
Closing Balance	**650**	**518**	**(500)**	**(500)**

Table 27. South Reserve for Injuries and Damages ($000)

	2001	2002	2003	2004
	Actual	Estimate	Forecast	Forecast
Opening Balance	(300)	(175)	(175)	(500)
Provision	125	(1)	(575)	(250)
Payments	-	1	250	250
Closing Balance	**(175)**	**(175)**	**(500)**	**(500)**

Views of the Applicant

ATCO Pipelines noted the Board's previous statements on RID[54] that the "level of the reserve is low enough to smooth out the expense over time, yet high enough to mitigate against any extraordinary occurrence or series of occurrences in a future year."

ATCO Pipelines confirmed that its request for reserve funding was based on one major claim every four years for each of APN and APS. ATCO Pipelines noted that past experience was not of much assistance in forecasting this expense. ATCO Pipelines stated that its proposal was based on its best judgment of the optimal reserve levels, and that its proposal should be approved as filed.

In Reply Argument, ATCO Pipelines noted that it would take 20 years to pay for the deductible for one major incident at the level proposed by AUMA/EDM/CG. ATCO Pipelines also noted that there was no established relationship between rate base and claims, and that the Calgary proposal to maintain a reserve of $175,000 for APS should be rejected.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG noted that ATCO Pipelines wished to provide for one major incident, with a $1,000,000 deductible, every four years – for both APN and APS. AUMA/EDM/CG noted that this would require a $1,268,000 provision to the reserve for APN and a $575,000 provision for APS in 2003, and $250,000 for each in 2004.

AUMA/EDM/CG argued that it was unreasonable to use APN claims to create a forecast for both APN and APS, as APS had experienced a lower number of claims. Further, AUMA/EDM/CG argued that major claims had arisen due to breaks at river crossings, and that the significant expenditures forecast by ATCO Pipelines to correct river crossings should reduce the risk of major failure.

54 Decision E93004, pp. 274-275

AUMA/EDM/CG argued that the annual forecast charge presented by ATCO Pipelines was not warranted and should be reduced to $50,000.

Calgary

Calgary argued that given the history of insurance charges for APS, a $500,000 annual charge to the RID did not seem appropriate for APS. Calgary argued that if a $500,000 reserve is appropriate for APN, the fact that the APS rate base is less than 30% of the APN rate base would suggest that the current $175,000 reserve for APS was sufficient.

Views of the Board

The Board notes that there are two aspects to the RID, the level of the annual charge to the reserve, and the target level of the reserve fund. The estimate for the position of the reserve funds at the end of 2002 was a deficit of $518,000 for APN and a balance of $175,000 for APS.

With respect to the annual charge to the reserve, the Board notes that the estimate provided by ATCO Pipelines assumes that there will be two major incidents every four years, equivalent to one incident every two years. The Board is of the view that this level of major property failures is improbable, and does not seem to be reflective of past experience or reasonable future expectations, especially when capital projects are being undertaken to mitigate problems with river crossings, as noted by AUMA/EDM/CG. For these reasons, ATCO Pipelines has not satisfied the Board that its proposed claims level is reasonable. Absent other evidence, the Board is of the opinion that a more reasonable claims level would be two major incidents every ten years, equivalent to one every five years. At a $1,000,000 deductible for current property insurance coverage, as referred to in Section 4.8 of this Decision, this claims level would imply an annual average expense of $200,000 for ATCO Pipelines North and South.

With respect to the target level of the reserve, the Board notes that, in the case of ATCO Pipelines, the reserve amounts are included as a credit to working capital and reduce the amount of return payable. Other utilities have credited such reserve amounts to no-cost capital, which has the same effect. In the case where the reserve balance is negative, customers lose the value of the credit to working capital or rate base, and must pay for additional return. Based on these considerations, the Board is of the view that customers and ATCO Pipelines should be relatively indifferent to the level of reserve capital.

The Board is of the view that it is reasonable to allow the reserve to accumulate enough funds to cover one major claim, or $1,000,000 every five years. If there is more than one major claim in a five-year period, the reserve fund could experience a deficit. However, the Board is not satisfied that there is a pressing need to bring the reserve to that level within the test period. Instead, the Board is of the view that the RID should be brought to $200,000 for 2003 and $400,000 for 2004, growing to $1,000,000 over five years.

Noting that as of January 1, 2003, the reserve balances were a $518,000 deficiency for APN and a $175,000 surplus for APS, the Board finds that bringing the ATCO Pipelines total reserve fund to $200,000 for 2003 would require a $543,000 provision for the year.

Accordingly, the Board directs ATCO Pipelines to provide for a $543,000 reserve for 2003 and $200,000 for 2004. The Board also directs ATCO Pipelines, in its next GRA, to file its policy regarding the charges to the RID, including the threshold amounts considered to be minimum

amounts chargeable to insurance or recoverable losses, below which expenses are considered normal operating expenses to be borne by the company. The Board expects that ATCO Pipelines will retain records of all charges to insurance and provide these records showing the incidents and amounts claimed for self insurance, the details and circumstances for each claim such that they can be assessed in the GRA.

The Board notes that, although the issue of allocation of reserve was raised by Calgary, it was not discussed by other parties. The Board is of the view that the allocation of the costs of the RID should be deferred to the Phase II proceeding, acknowledging that North and South customers should receive the benefit or pay for outstanding prior period balances for their respective reserve accounts.

4.7 NGTL Charges

Background

ATCO Pipelines included placeholder amounts for NGTL charges as part of the Application. Total placeholder values for these charges were $8.4 million for 2003 and $12.9 million for 2004.

Views of the Applicant

ATCO Pipelines noted that the Board had recently approved changes to the NGTL charges, which were different from the basis used in preparing the Application. ATCO Pipelines stated that it would finalize the correct value of these placeholders through further compliance filings.

Views of the Board

The Board directs ATCO Pipelines to finalize the corrected values of the NGTL placeholders in the Refiling to this Decision.

4.8 Insurance Expenses

Views of the Applicant

ATCO Pipelines stated that it relied on the specialized expertise and buying power of the ATCO Group to obtain the lowest premiums and best management of risks. ATCO Pipelines further stated that post September 11, 2001 there had been an effect on insurance costs, premiums and coverage. Some risks could not be insured, or could only be insured at prohibitive expense.

ATCO Pipelines refuted the notion that there was a direct correlation between O&M levels and insurance costs. ATCO Pipelines submitted that it had provided for reasonable and prudent insurance coverage, and that the insurance expense should be approved as filed.

ATCO Pipelines argued that the AUMA/EDM/CG analysis supported the statements of its witnesses, that insurance costs had risen significantly since 2001. ATCO Pipelines noted that AUMA/EDM/CG had not provided any evidence regarding the increase in costs arising due to increased coverage.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG noted that forecast insurance expenses for 2004 were 231% higher than the 2001 actuals ($1,308,352 being the total 2004 forecast premium expense, and $395,450 being the 2001 actual premium expense). AUMA/EDM/CG noted a significant increase in coverage between 2001 and subsequent years, with coverage increasing from $250,000 to $1,000,000 for property including pipelines. AUMA/EDM/CG argued that this level of coverage was excessive, and was unsupported by ATCO Pipelines. AUMA/EDM/CG submitted that insurance expenses should be limited to the 2002 level of $782,586.

Calgary

Calgary stated that the increase in insurance expense appears to be attributable to the increase for RID.

Views of the Board

The Board notes the argument of AUMA/EDM/CG that the rapid increase in insurance costs for ATCO Pipelines may be attributable to excessive insurance coverage for property damage, including pipelines. The Board has reviewed the categories of insurance for ATCO Pipelines and notes that the property insurance coverage purchased by ATCO Pipelines has increased. At the same time, insurance deductibles have also increased.

The Board has also reviewed other categories of insurance purchased by ATCO Pipelines and notes that, for example, the cost of purchasing insurance for gas in storage is forecast to increase 222% from 2001 actuals to 2004,[55] and the cost for excess liability insurance is forecast to increase 289%[56] over the same period. The coverage and deductible conditions for these types of insurance did not change between 2001 and 2004.

The Board concludes that, on balance, the evidence in this case points to a general increase in insurance costs following September 11, 2001, as noted by ATCO Pipelines. The Board notes that this conclusion is consistent with the views expressed by the Board in Decision 2003-071 in relation to insurance premiums for ATCO Electric Ltd.[57] Therefore, the Board accepts the forecast insurance costs for ATCO Pipelines for 2003 and 2004 as reasonable. However, because the increases result in substantial additional costs to customers, the Board directs ATCO Pipelines, at its next GRA, to provide detailed justification for the coverage and deductible limits it proposes for all categories of insurance.

4.9 ATCO I-Tek Affiliate Service Expenses

Background

ATCO I-Tek provides information system services to the ATCO Companies.

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55 AUMA/EDM/CG. [CAL-AP.110(c)], 2001 Actual Premium Costs $11,942, 2004 Forecast Premium Costs $38,480

56 AUMA/EDM/CG. [CAL-AP.110(c)], 2001 Actual Premium Costs $23,551, 2004 Forecast Premium Costs $91,563

57 Decision 2003-071, p. 151

The review of the ATCO I-Tek pricing, service levels, and other contractual matters is the subject of an ongoing parallel regulatory process initiated in Application #1285881, ATCO I-Tek Information Technology Master Services Agreement (MSA Module). The Board issued Decision 2003-073 in relation to the MSA Module on September 26, 2003.[58] A benchmarking process in respect of ATCO I-Tek charges for services will follow.

This Application includes a review of appropriate service volumes and capital projects undertaken by ATCO I-Tek for ATCO Pipelines.

Views of the Applicant

In argument, ATCO Pipelines anticipated that Calgary would argue for a reduction in IT expenses on the basis of the information in the 2001 Gartner study. ATCO Pipelines argued that the information in that study was suspect, and not relevant to its situation. ATCO Pipelines also argued that, due to the shortcomings in the interveners' evidence, no weight should be given to interveners' arguments in this matter. ATCO Pipelines submitted that no evidence had been provided refuting its forecast IT volumes, and requested approval for these amounts as submitted.

In Reply Argument, ATCO Pipelines argued that the AUMA/EDM/CG assertion that productivity of I-Tek services was declining ignored the evidence that the increased service volumes were a result of increased use of the Transportation Information System (TIS) and Gas Management System (GMS). ATCO Pipelines noted that its Application had indicated that the implementation of line pack management and system balancing required a significant increase to the amount of information that must be collected.

ATCO Pipelines argued that Calgary's conclusion regarding distributed costs was incorrect, and that these costs arose from the increased functionality of the TIS. ATCO Pipelines noted that this has reduced reliance on mainframe applications.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG noted that the increases in ATCO I-Tek charges were the result of increased service levels associated with the added functionality and usage of the TIS, TIS Online, and GMS systems. AUMA/EDM/CG argued that the increase in activity levels for IT services was not supported by increases in the number of customers, the volume of sales, or quality of service measures. AUMA/EDM/CG argued that the increase in service levels for the use of ATCO I-Tek services indicated a decrease in the productivity for those services. AUMA/EDM/CG submitted that the ATCO I-Tek volumes should be maintained at the 2001/2002 actual levels, for the 2003/2004 test period.

For the purpose of placeholder amounts, AUMA/EDM/CG recommended that the unit rates used should be those approved in Decisions 2002-069 and 2002-097.

[58] Decision 2003-073, ATCO Electric, ATCO Gas, and ATCO Pipelines (the ATCO Utilities), ATCO I-Tek Information Technology Master Services Agreement (MSA Module) (September 26, 2003)

Calgary

Calgary noted that the increase in ATCO I-Tek volumes was related to the increased usage of GMS. Calgary recommended that the Board order ATCO Pipelines, for all future GRAs, to provide a table of ATCO I-Tek volumes in the same manner as contracted from its I-Tek affiliate, showing both operating and project development volumes for the forecast years and three prior years. Calgary recommended that an explanation should be provided for any forecast variance over 10%.

Calgary noted in Reply Argument that its reliance on industry metrics was due to not having volume information available from ATCO Pipelines, and noted that subsequent analysis was provided in the Calgary Argument. Calgary recommended that the Board accept its proposals with regard to the information that should be available for ATCO I-Tek services at subsequent GRAs.

Calgary also noted that the allocation of IT expenses for APN and APS was too high for APS, and that the Shared Services policy of ATCO Pipelines should be revised to allocate only 33% of the IT costs to APS.

Views of the Board

The Board notes the disagreement among parties on the level of service volumes that would be appropriate for ATCO I-Tek affiliate services for the test period for ATCO Pipelines. On the one hand, ATCO Pipelines has requested an increase in service levels arising from increased use of the TIS and GMS systems. On the other hand, AUMA/EDM/CG has requested that the Board freeze service levels equivalent to prior years' usage. The Board notes that the evidence provided by ATCO Pipelines linked the increase in ATCO I-Tek usage rates to the proposed new IT capital projects. The Board is not persuaded that it is appropriate to freeze the ATCO I-Tek volumes at prior years' values, because it would not reflect changes in ATCO Pipelines' business from prior years. However, the Board is of the view that it is appropriate for the ATCO I-Tek operations expenses to be consistent with approved capital projects for the test period.

The Board agrees with the recommendation of AUMA/EDM/CG, and directs ATCO Pipelines to use the current ATCO I-Tek charges approved in Decisions 2002-069[59] and 2002-097[60] in determining placeholder values for ATCO I-Tek affiliate services. The Board notes that the final values for these charges will be determined from the ongoing ATCO I-Tek benchmarking process.

The Board also agrees with the recommendation of Calgary as to the appropriate detail required for ATCO I-Tek capital and operations expenses. The Board directs ATCO Pipelines, in all future GRAs, to provide a table of ATCO I-Tek volumes contracted from its I-Tek affiliate, showing volumes for operating the existing systems for the 3 preceding years and forecast test years and volumes for new project development for the forecast test years.

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59 ATCO Electric Ltd. and ATCO Gas and Pipelines Ltd. ATCO Affiliate Transactions and Code of Conduct Proceeding – Part A: Asset Transfer, Outsourcing Arrangements, GRA Issues

60 ATCO Gas South
2001/2002 General Rate Application, Carbon Storage Transfer and Part A: Asset Transfer, Outsourcing Arrangements, and GRA Issues Compliance Filing

4.10 Other Affiliate Services Expense

Background

Other Affiliate Service expenses include head office cost allocations and other smaller affiliate company services.

Views of the Applicant

ATCO Pipelines stated that there was no evidence provided by the interveners opposing the costs proposed for other affiliate services, and that the forecast amounts for these expenses were reasonable.

ATCO Pipelines refuted the argument of AUMA/EDM/CG, noting that the 2002 actual amounts for other affiliate services were close to the projected amounts, and that no request was made for any further explanation of those amounts. ATCO Pipelines argued that there was no basis for limiting increases to the forecast rate of inflation, and requested that other affiliate service costs be approved as submitted.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG noted the ATCO/CUL Corporate Administrative Expenses increased from the actual 2001 values, through the 2004 forecast year:

Table 28. Corporate Administrative Expenses

2001 Actual	$1,181,000
2002 Estimate	$1,376,000
2003 Forecast	$1,426,000
2004 Forecast	$1,466,000

AUMA/EDM/CG submitted that ATCO Pipelines had not provided any explanation for the significant increase in 2002 corporate administrative expenses, over 2001. AUMA/EDM/CG argued that the increase in these expenses should be limited to the rate of inflation.

Calgary

Calgary recommended that, other than for the small charges for ATCO Gas, that the amounts for Affiliate Services should be treated as placeholders. Calgary noted that there is a benchmarking process underway for ATCO I-Tek, and that there is to be an examination of executive compensation – forming part of the ATCO/CUL administrative charges.

Views of the Board

The Board notes that a substantial portion of Other Affiliate Services Expenses is related to corporate executive compensation. The Board agrees with Calgary that it is appropriate to keep that portion of Other Affiliate Services Expense as a placeholder, and await the results of the ongoing ATCO Executive Compensation proceeding, which will provide more appropriate

information in relation to these costs.[61] The Board also agrees with Calgary that I-Tek service fees will be benchmarked and considers that the results of the benchmarking exercise should be applied to the test years in respect of these fees. Therefore, the Board considers that it would also be appropriate to approve placeholders for these costs at this time.

The Board directs ATCO Pipelines, in its Refiling, to separate and identify the portion of Other Affiliate Services Expense related to ATCO executive compensation and the portions relating to the I-Tek service fees to be benchmarked. The Board further directs ATCO Pipelines to adjust those amounts, in due course, to comply with the Board's decisions arising from the ATCO Executive Compensation proceeding and from the I-Tek benchmarking process. Finally, with respect to the remaining portions of the Other Affiliate Services Expenses, [i.e. those relating to ATCO Gas charges and those relating to ATCO Group charges and ATCO I-Tek charges that are not subject to review], respectively, in the ATCO Executive Compensation proceeding and the ATCO I-Tek benchmarking process, the Board directs ATCO Pipelines, in its Refiling, to adjust these amounts subject to the revised inflation rates.

5 DEPRECIATION AND AMORTIZATION[62]

5.1 Depreciation Expense

Background

On May 7, 2003, ATCO Pipelines held a technical meeting on depreciation issues with interveners. By letter dated May 30, 2003, ATCO Pipelines indicated that the intervener witnesses at this meeting suggested that a negotiated settlement on depreciation might be possible.

On June 2, 2003, ATCO Pipelines provided notice to all ATCO Pipelines 2003/2004 GRA Interested Parties of a negotiation meeting to be held on Thursday, June 5, 2003, and invited interested parties to indicate any opposition to the proposed negotiations. No objections were received.

The Depreciation Settlement for 2003 and 2004 was reached on June 5, 2003, and filed with the Board on June 13, 2003. The Depreciation Settlement was negotiated between and signed by ATCO Pipelines, Calgary, AUMA/EDM/CG, and FGA.

On June 16, 2003, the Board sent a letter to all Interested Parties to the ATCO Pipelines 2003/2004 GRA inviting comments by June 19, 2003 on the Depreciation Settlement. The responses to this letter are outlined below. No objections to the Depreciation Settlement were received.

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[61] Application No. 1310259

[62] Depreciation distributes fixed capital costs less net salvage over the forecast service life of the asset by allocating annual amounts to expense. Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, or over the life of the asset or liability to which the account applies, or over the period during which it is anticipated that the benefit will be realized. Normally the distribution of the total is in equal amounts to each year of the amortization period.

Views of the Applicant

ATCO Pipelines submitted that the Depreciation Settlement was in the public interest, reasonable and fair to all parties, rationally substantiated, and supported by a complete and adequate application. ATCO Pipelines submitted that the Depreciation Settlement should be approved as filed.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG submitted that the Depreciation Settlement should be approved, subject to any modifications required in a compliance filing to address adjustments to opening rate base balances or capital expenditure forecasts.

As well, individual member organizations of the Consumers' Group provided support for this agreement:

- PICA provided its support for the Depreciation Settlement via e-mail dated June 17, 2003;
- Aboriginal Communities provided its support for the Depreciation Settlement via e-mail dated June 18, 2003; and
- AIPA provided its support for the Depreciation Settlement via e-mail dated June 19, 2003.

Calgary

Calgary recommended that the Board approve the Depreciation Settlement as a whole, noting that compromises had been reached between parties to the agreement.

FGA

FGA supported the Depreciation Settlement, noting that this agreement had resulted in reduced hearing costs. FGA stated that the Depreciation Settlement was in the public interest.

IGCAA

IGCAA provided its support for the Depreciation Settlement via e-mail dated June 16, 2003.

Views of the Board

The Board notes that the Depreciation Settlement was reached between ATCO Pipelines, AUMA/EDM/CG, Calgary and the FGA. The Board notes that indications of support were also received from PICA, Aboriginal Communities, AIPA, CAPP and IGCAA. No parties opposed the Depreciation Settlement.

Accordingly, the Board will consider whether ATCO Pipelines' settlement process was fair and in accordance with the Board's Negotiated Settlement Guidelines (IL98-04 Revised), and whether the Depreciation Settlement may result in rates that are not just and reasonable.

In earlier decisions the Board has indicated that ordinarily, for unanimous or otherwise unopposed settlements, the Board will only intervene "...in circumstances where the settlement is patently against the public interest or contrary to law."[63]

The Board considers that a settlement is fair and in accordance with the Board's Negotiated Settlement Guidelines if proper notice has been provided, no negative response was received to the notice for objections, due process has been provided to the participants by allowing for meaningful participation in the process including the funding of interveners' participation, Board staff has participated as an observer in the settlement discussions, and all parties expressing an interest have signed off on the settlement.

The Board is satisfied that proper notice to parties was provided in the present case. The Board notes that no objections to the Depreciation Settlement were received. Furthermore, a Board observer was present for negotiations, and indicated to the Board that parties were able to participate meaningfully in the negotiation process. The Board also notes that counsel and experts in depreciation matters represented interveners during settlement discussions.

The Board also notes that all parties involved in the negotiation have signed the Depreciation Settlement. Accordingly, the Board is satisfied that the Depreciation Settlement process was fair, and in accordance with the Board's Negotiated Settlement Guidelines.

The Board has examined the details of the Depreciation Settlement, and notes that it has been reached as a compromise among a number of issues. The Board has examined the effect of each of the changes noted in the Depreciation Settlement and has not found any part of the Depreciation Settlement that is likely to result in rates for customers that are not just and reasonable or that are patently contrary to the public interest. Further, the Board notes that the overall effect of the Depreciation Settlement is to reduce the revenue requirement by a direct $850,000 reduction in depreciation expense, as well as by $120,000 transferred from operating expenses to capital expenses. The Board is satisfied that the Depreciation Settlement is not patently contrary to the public interest.

Accordingly, the Board approves the Depreciation Settlement and directs use of the depreciation parameters in the Depreciation Settlement for the purposes of revising the forecast depreciation expense and accumulated depreciation balances in the test years applicable to the revised opening balances addressed in Section 2.2.8 and revised capital additions addressed in Section 1.1.1 of this Decision.

[63] See Decision 2002-116, 2002 Rates, Amended North Core Agreement and Sale of Beaverhill Lake and Fort Saskatchewan Properties at page 7, and Decision 2000-85, Northwestern Utilities Limited Approval of Rates, Tolls, Charges, and Terms and conditions of Service for Core Customer, and Approval of Amendments to the North Core Agreement, at p. 7.

6 INCOME TAX

6.1 Flow-Through vs. Deferred Income and Capital Taxes

Background

APN has used the deferred tax accounting method for federal tax, while using the flow-though method for provincial tax. APS has been using the flow-through method for both the federal and provincial tax calculations.

Views of the Applicant

ATCO Pipelines stated that it wished to amend its North Federal income tax methodology to the flow-through method. ATCO Pipelines noted that this would reduce the income tax expense by $242,000 for 2003, and $209,000 for 2004.

ATCO Pipelines requested that the Board defer the disposition of the credit balance in the deferred income tax account, to allow it to deal with the un-recovered deferred pension balance. ATCO Pipelines noted that the deferred tax credit would reduce working capital for the test period.

In Reply Argument, ATCO Pipelines stated that it had no objection to offsetting the deferred pension balance against the deferred tax balance in this test period, if the Board so ordered. ATCO Pipelines noted that it had no intention of transferring any benefit resulting from deferred income taxes from APN to APS customers.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG noted that ATCO Gas North had proposed to make a one-time refund to customers of its deferred tax credit. AUMA/EDM/CG recommended that APN be directed to also refund its deferred tax credit, either through ATCO Gas North, or separately and concurrently with the ATCO Gas North refund filing.

AUMA/EDM/CG stated that the issue of the deferred tax credit should be dealt with in the current test period, to avoid the possible transfer of benefit from APN to APS customers.

Calgary

Calgary stated that there were benefits to having APN and APS use the same tax approach. Calgary stated that, although it was not directly involved in the disposition of the deferred tax credit for APN, it supported separate treatment of the deferred tax and deferred pension.

Views of the Board

The Board notes that ATCO Pipelines proposed to change the income tax treatment for APN to flow-though, which has the effect of reducing the revenue requirement during the test period by $242,000 for 2003 and $209,000 for 2004. Since the change in the income tax treatment will benefit customers and simplify future regulatory filings, the Board approves the change for APN to the flow-through method.

The Board has considered the request of ATCO Pipelines to defer dealing with the credit balance in deferred income tax until such time as the debit balance in the deferred pension account is resolved. The Board has considered the treatment of the deferred pension account in Section 4.4 of this Decision. The Board is of the view that resolution of the deferred pension issue cannot be completed in this test period, and further that there are several possible resolutions to that issue. Therefore, the Board does not believe it would be appropriate to delay the disposition of the credit balance in the deferred tax account and considers it more reasonable to deal with the credit balance in the current test period.

Accordingly, ATCO Pipelines is directed to propose a method to refund the credit balance of the deferred tax account to customers in the Refiling arising from this Decision.

6.2 Rainbow Case Income Tax Considerations

Background

The issue of concern related to the Rainbow and Canderel tax cases involved distinguishing expenditures for replacement costs, considered to be of a non-recurring and enduring nature and therefore capital costs, versus those costs for recurring repairs and maintenance, which are deductible for income tax purposes in the year incurred. The result of these cases was that maintenance expenses are considered to be deductible for income tax purposes in the year they are incurred, even if these expenses are capitalized.

Views of the Applicant

ATCO Pipelines noted that the amounts of $4.692 million and $4.886 million for 2003 and 2004 respectively were deducted as indirect overhead expenses related to the Canderel and Rainbow cases.

ATCO Pipelines responded to the argument of AUMA/EDM/CG that additional information should be provided regarding indirect overhead expenses, noting that it had already identified what is included in these amounts in response to AUMA/EDM.AP-49.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG noted that ATCO Pipelines had deducted $4.692 million in 2003, and $4.886 million in 2004, for indirect overhead expenses in calculating taxable income.

AUMA/EDM/CG noted that the company does not have any written policies with respect to the types of expenses covered by these deductions, and stated its concern that the company had too much discretion in these matters, allowing possible abuse. AUMA/EDM/CG argued that ATCO Pipelines should be required to file a written policy regarding the detailed use of the indirect overhead deduction, and should provide a detailed variance analysis between actual and forecast deductions for the next GRA.

Calgary

Calgary stated that it did not appear that there was any explicit recognition of the Rainbow/Canderel maintenance related expenditures in ATCO Pipelines' calculation of income

taxes. Calgary estimated that there would appear to be $1 million to $2 million of maintenance related capital expenditures.

Views of the Board

The Board notes the evidence by ATCO Pipelines that maintenance related expenses and overheads were accounted for in its Application. The Board is satisfied that the expenses noted in relation to the Canderel and Rainbow tax cases have been properly accounted for in the test period.

The Board notes the concerns of AUMA/EDM/CG that the description of ATCO Pipelines' policies regarding these tax deductions is not sufficiently detailed. The Board has reviewed the response of ATCO Pipelines to AUMA/EDM.AP-29 and agrees with AUMA/EDM/CG that the noted policy statement is lacking sufficient detail. The Board directs ATCO Pipelines, at the next GRA, to file a written policy regarding the detailed use of the indirect overhead deduction and to provide a detailed variance analysis between actual and forecast deductions.

6.3 Prior Period Indirect Overhead Deductions

Background

AUMA/EDM/CG argued that adjustments to 2001 and prior years' taxes, arising from the Canderel and Rainbow tax decisions, should be refunded to consumers.

Views of the Applicant

ATCO Pipelines argued that the position taken by AUMA/EDM/CG implied that the Board did not understand the future implications on UCC balances when it issued Decision 2001-97. ATCO Pipelines noted that this specific issue was brought to the Board's attention in that proceeding.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG noted evidence from the transcript that shareholders had benefited from indirect overhead deductions prior to 2001, to the extent prior period indirect overhead deductions are not reflected in the federal deferred tax account.

AUMA/EDM/CG noted that the Board had determined in Decision 2001-97 that prior period adjustments arising from isolated transactions outside of the test year were not subject to deferral to the test period. However, AUMA/EDM/CG argued that the issue was one of symmetry of expenses and benefits, that customers were responsible for paying for the capital cost of the indirect overhead charges capitalized, that resulted in tax savings because of the Canderel decision, and should receive those tax savings.

AUMA/EDM/CG noted that, because of the agreement in place with APN during the period in question, it was only the provincial tax savings that were at issue for APN. For APS, AUMA/EDM/CG requested that the Board either direct the refund of these tax savings to consumers, or deem the Undepreciated Capital Cost (UCC) for ATCO Pipelines be restored to a higher level.

Views of the Board

Although the argument put forward by AUMA/EDM/CG is different from the argument that was advanced on this same issue in the proceeding leading up to Decision 2001-97, the Board is of the view that the circumstances of the cases and the prevailing principle remain the same.

The Board notes that ATCO Gas and Pipelines did gain, by means of reduced taxes, in the years 2001 and prior, due to the application of principles referenced in the Canderel and Rainbow cases. This was different from what was considered and approved where the Board had established rates for those years. However, other items are undoubtedly also different from the prospective materials used to establish those rates, both harmful and beneficial to customer interests. AUMA/EDM/CG also noted that the federal tax benefit from indirect overheads would have been recorded for the benefit of customers of APN and they did not take issue with the provincial portion, since it was likely dealt with as part of the 2001 re-opener negotiations.

The Board is not convinced in the circumstances that it would be appropriate to undertake a further review on retrospective rate matters, which were not the subject of any deferral account or place holder value and therefore, will not order a review of prior period tax matters in this case.

6.4 Use of Current and Proposed Income Tax Rate

Background

Evidence was submitted on the record of this proceeding indicating that the actual income tax rate would be changed during the test years and would differ from the tax rate forecast in the Application. The evidence showed that the changes to tax rates were more certain at the federal level than at the provincial level.

Views of the Applicant

ATCO Pipelines submitted that selected items, such as tax rate changes, should not be adjusted from the forecast. ATCO Pipelines submitted that it was unfair to change some forecast items, and not all. ATCO Pipelines noted that items such as increased working capital arising from increases in the cost of line pack gas and the impact of Rider B – AUMA Template Franchise Agreement not having been put in place would increase the cost to customers from the filed forecast.

In Reply Argument, ATCO Pipelines argued that AUMA/EDM/CG had proposed a new, and untested, proposal for dealing with changes to tax rates. ATCO Pipelines argued that the AUMA/EDM/CG proposal to use a deferral account to capture tax rate changes was inconsistent with prospective rate making.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG argued that ATCO Pipelines had no control over changes in tax rates. AUMA/EDM/CG suggested that any changes to the tax expense should be calculated by reference to the forecast taxable income and collected in a deferral account for the benefit of customers.

In Reply Argument, AUMA/EDM/CG stated that it was appropriate to adjust the revenue requirement based on announced legislated changes to the extent they were material. AUMA/EDM/CG noted that ATCO Pipelines had not quantified offsetting cost increases due to any other legislative changes.

Calgary

Calgary argued that the provincial tax reduction should be reflected in the calculation of revenue requirement, as well as the federal budget reduction of the large corporation income tax to 0.2% in 2004 and the increase in minimum threshold to $50 million.

Views of the Board

The Board notes its previous position on the determination of forecast tax expense as set out in Decision 2001-97, and other decisions. In Decision 2001-97 the Board noted that Section 3465 of the CICA Handbook specifies that income tax assets and liabilities should be measured using the income tax laws and rates that are expected to apply when the asset is realized or liability settled. Further, Section 3465 states that it would be appropriate to use a substantively enacted rate that the Government is able and committed to enacting in the foreseeable future.[64] In a forecast-based jurisdiction such as Alberta, the Board considers that a fair and reasonable estimate of the future tax rates is not necessarily the enacted rates but the rates that best reflect government intentions, provided that the risk of rates not being implemented is taken into account. The Board concurs with AUMA/EDM/CG that the tax rates enacted by federal and provincial governments are outside of the control of the utility, and are thus candidates for deferral account treatment.

The Board notes that, in this case, there is substantive evidence that the federal government intended to amend the large corporation tax, applicable to ATCO Pipelines. The Board notes that these changes were announced in the Notice of Ways and Means Motion, 2003 Budget Proposals – March 19, 2003 (Special Report CCH), entered as Exhibit 29-39 in these proceedings.

The Board is also of the view that provincial tax changes have been announced with an adequate degree of certainty to require a change to forecast income tax expense.

The Board notes that the rates of Provincial income tax proposed in the 2003 Provincial Budget were 12.5% (2003) and 11.5% (2004), whereas ATCO used the existing rate of 13% in calculating income tax expense. The Board considers that, although the amended rates have not yet been enacted, inclusion in the Provincial Budget gives the certainty envisaged in the CICA Handbook for application to corporations.

Therefore, the Board directs ATCO Pipelines, in its Refiling, as a placeholder, to use the rates that have been announced by the governments notwithstanding that the announced rates have not yet been enacted. Accordingly, recognizing that the rates are to be effective as of April 1, 2003, the Board directs ATCO to recalculate income tax expense to reflect the revised Provincial Income Tax rates of 12.62% (2003) and 11.75% (2004) on an annualized basis.

In addition to using the announced rates, the Board considers that an appropriately constructed deferral account would be fair for both customers and the company to capture any changes in

[64] Decision 2001-97 pp. 76 - 77

Federal and Provincial tax rates over the test period. Accordingly, the Board directs ATCO to propose a deferral account in its Refiling that would account for any change in Federal resource allowances and tax rates and Alberta tax rates.

7 TRANSPORTATION REVENUE

7.1 Transportation Revenue Forecasts

ATCO Pipelines provided its transportation revenue forecast for the total system, and the North and South systems in Tables 5.1-1 to 5.1-3 of the Application. ATCO Pipelines also provided a breakdown of each of the major revenue categories and a commentary explaining the 2003 and 2004 test years, including any significant changes from prior years.

Views of the Applicant

ATCO Pipelines submitted that it was able to forecast revenue with a great degree of accuracy, and that the transportation revenue forecast was well supported. ATCO Pipelines submitted, for example, that the producer revenue forecasts were based on actual receipt flow history and ongoing dialogue with its customers with respect to new production, declines and competitive position. ATCO Pipelines also submitted that industrial revenue forecasts were based on actual flow history and dialogue with customers.

ATCO Pipelines responded to Calgary's suggestion that there was information asymmetry with respect to the transportation revenue forecast. ATCO Pipelines argued that extensive information in the form of detailed historical and forecast billing determinants and volumes supporting the revenue forecasts was provided. Further, ATCO Pipelines argued that a comprehensive discussion and review of the reasons for contract demand terminations and the receipt points where the terminations were occurring was provided. ATCO Pipelines submitted the Board already ruled on the sufficiency of information responses and that Calgary's suggestion was improper.

ATCO Pipelines argued that no intervener presented evidence to contradict the ATCO Pipelines revenue forecast.

Views of the Interveners

Calgary submitted there were concerns regarding information asymmetry that impacted Calgary's ability to test ATCO Pipelines' forecast of demand de-contracting and transportation revenues. Calgary referred to information deficiencies with respect to historical data and volumetric information, and the process whereby ATCO Pipelines eventually provided certain information. Calgary argued the process was very time consuming and inefficient, and that it was not able to obtain the information required to prepare an alternative forecast.

Views of the Board

The Board notes that Calgary suggested there was information asymmetry with respect to the transportation revenue forecast. The Board considers that the utility will undoubtedly be in a superior position in terms of its ability to access certain types of commercial, internal, proprietary and confidential information, compared to interveners. Furthermore, the utility will

be in a superior position with respect to the degree to which that information, and other publicly available information, was reflected in its forecast (if at all).

Therefore, the Board considers that Calgary has raised a valid issue regarding the process by which ATCO Pipelines, or any other utility, should disclose the information it relied upon to prepare its forecast. The Board believes the utility should be 'discouraged' from providing minimal information in the application, or from providing it in a piecemeal way via responses to information requests, undertakings, or pursuant to various procedural motions.

Forecasts should be constructed in such a way that they can be readily 'tested', rather than developed in a fashion whereby a variety of factors are referred to, but not incorporated into the forecast in a manner that can be quantified or verified by the Board or interveners. The Board considers that the onus is on the Applicant to make its case, rather than on the interveners to disprove it.

The Board will address the various categories of ATCO Pipelines' transportation revenue forecast in detail. The forecast for each category will be addressed on its own merit, based on the evidence. The Board will also address the implementation of a deferral account with respect to the producer revenue forecast.

7.2 Deferral Accounts

Deferral accounts for volatile revenue components have been recommended by several parties, and carefully considered by the Board during the proceeding and in its deliberations in reaching this Decision. AUMA/EDM/CG, Calgary, and CAPP have advocated revenue deferral accounts. The Board has been urged to provide direction regarding the use of deferral accounts related to various types of transportation revenue.

7.2.1 Use of Deferral Accounts

This section will focus on the general principles, as opposed to the specific demand and throughput volume deferral accounts advocated by certain interveners.

Views of the Applicant

ATCO Pipelines argued that deferral accounts were not the preferred method of regulation in Alberta, and would not be appropriate in the current circumstances. ATCO Pipelines submitted that deferral accounts would only be appropriate for items that were of material significance and difficult to forecast. ATCO Pipelines referred to previous Board Decisions[65] in support of its views. ATCO Pipelines submitted that it had always operated with very few deferral accounts, whereby the ratemaking process captured significant incentives and efficiencies for the benefit of customers. ATCO Pipelines argued that wrapping a company in deferral accounts would not promote efficiencies in a utility and was not consistent with prospective ratemaking.

ATCO Pipelines argued that revenue forecasts were not beyond its control, rather the problem was with level playing-field issues. ATCO Pipelines stated there were off-setting factors in the transportation revenue forecast (related to the impact of change in natural gas prices) regarding revenue from industrials and producers, that led to very accurate forecasts compared to actual

[65] Decisions U99099, 2000-9, and 2000-82

amounts. ATCO Pipelines argued the transportation revenue forecast was well supported by the evidence.

ATCO Pipelines argued that deferral accounts did not necessarily reduce risk. ATCO Pipelines suggested, for example, there was risk created by the fluctuations of the exchange deferred account (EDA). ATCO Pipelines argued the EDA was and would continue to have a significant negative impact on ATCO Pipelines' operations, causing rate fluctuations and rate uncertainty for customers that resulted in ATCO Pipelines being much less competitive. ATCO Pipelines argued that transportation revenue deferral accounts also had the potential to create rate fluctuations arising from the disposition of the deferral account, inter-generational inequities to the extent that customers terminate service, and reduced incentives to utilities.

ATCO Pipelines replied to the CAPP argument that ATCO Pipelines should not be compensated for volume risk. ATCO Pipelines submitted that it had not requested compensation for revenue forecast risk, and further, that its revenue forecast was accurate. ATCO Pipelines also replied to the CAPP suggestion that it should use revenue deferral accounts similar to those of NGTL. ATCO Pipelines argued there were significant differences between NGTL and ATCO Pipelines that affected the appropriateness, or in this case inappropriateness, of such deferral accounts.

ATCO Pipelines argued that while AUMA/EDM/CG recommended the use of a revenue deferral account, AUMA/EDM/CG did not support their recommendation with any evidence.

ATCO Pipelines submitted that it was unnecessary for the Board to impose transportation revenue deferral accounts, thereby departing from the Board's historical practice. ATCO Pipelines argued there was no evidence provided of any benefit to support the adoption of NGTL type deferral accounts for ATCO Pipelines. Rather, ATCO Pipelines suggested there was evidence provided to illustrate the negative impact that a deferral account could have whereby prior period costs increased rates which could lead to contract terminations. ATCO Pipelines concluded that the interests of customers were best served without revenue deferral accounts.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG argued that deferral accounts were a well-established and accepted practice for NGTL and that they were appropriate for ATCO Pipelines in the circumstances. AUMA/EDM/CG submitted those circumstances included gas production declines, competitive issues between ATCO Pipelines and NGTL, and significant decreases in producer throughput.

Calgary

Calgary argued that deferral accounts protected both the utilities and ratepayers from uncertainty. Calgary submitted that when there was a major difference of opinion as to the appropriateness of a forecast, or where the applicant claimed that it could forecast accurately, but then either could not provide the data[66] or provided evidence clearly showing that it could not forecast accurately, then deferral accounts protected both the utility and the ratepayers.

[66] See Calgary's Argument at pages 85 and 86 with respect to CAL.AP-92 and Exhibit 29-02.

CAPP

CAPP submitted that revenue deferral accounts could be established and administered in a fashion like NGTL's, thereby capturing variances in firm service demand and throughput volume revenue. CAPP argued that the deferral accounts should be applied on an annual basis, and that "The risks, positive or negative, of volume variances that are not within ATCO's control should rest with ratepayers."[67]

CAPP replied to the ATCO Pipelines argument that revenue deferral accounts created inter-generational inequity. CAPP argued that the ATCO Pipelines customer base seemed to remain much the same from year to year.

CAPP submitted that revenue deferral accounts were a reasonable mechanism that would allow ATCO Pipelines to reduce its risk. CAPP suggested that ATCO Pipelines viewed revenue accounts as a disincentive in that it removed the opportunity for ATCO Pipelines to benefit from increased revenues, and that ATCO Pipelines might not be inclined to operate in an efficient manner.

CAPP submitted that ATCO Pipelines, as well as all other regulated pipelines, should operate as efficiently as possible – in all circumstances. CAPP argued the notion that a regulated pipeline would let efficiency suffer because an incentive (in the pipeline's eyes) was not approved should be rejected in the strongest terms.

CAPP argued revenue deferral accounts were fully consistent with prospective ratemaking because they transferred variances to a future year for consideration in that year. In this sense revenue deferral accounts were no more "inequitable" than using prospective ratemaking, a concept ATCO Pipelines noted it wanted to keep, and was concerned about being eroded.

CAPP submitted it was not uncommon in the pipeline business to have revenue deferral accounts. CAPP suggested that ATCO Pipelines was transitioned from being an LDC, and was now more into the pipeline category. CAPP argued revenue deferral accounts were quite common for regulated pipelines and were an appropriate risk reduction measure.

Views of the Board

As noted in the introduction to this section, the Board intends to initially deal generally with revenue deferral accounts.

The Board notes that while ATCO Pipelines has not previously used revenue deferral accounts, and does not want the Board to approve the use of revenue deferral accounts for the 2003/2004 test years, the use of revenue deferral accounts is not uncommon for regulated pipelines (including NGTL), and is the preferred approach urged on the Board by a substantial and varied group of customers, represented by AUMA/EDM/CG, Calgary and CAPP. The Board notes ATCO Pipelines' submission that the wholesale use of deferral accounts is not the preferred method of regulation in Alberta, however they have been used in various situations.

67 CAPP Evidence, Exhibit 10-07, p. 13

The Board does not consider there to be a definitive Board policy regarding the use of deferral accounts. Rather, the Board's practice has been to evaluate the use of a deferral account on a case-by-case basis, on its own merit. The Board notes that ATCO Pipelines and the interveners suggested several criteria for the Board to consider in this situation including:

- Materiality of the forecast amount,
- Uncertainty regarding the accuracy and ability to forecast the amount,
- Whether or not the factors affecting the forecast are beyond the utility's control,
- Whether or not the utility is typically at risk with respect to the forecast amount.

The Board notes that the criteria were suggested to address differing views with respect to risk, rate fluctuations, intergenerational inequity, and the Board's historical approach to deferral accounts. The Board considers that the suggested criteria are reasonable and will be discussed further in the next section when the Board addresses the need for demand and throughput volume revenue deferral accounts.

7.2.2 Demand and Throughput Volume Deferral Accounts

The use of revenue deferral accounts with respect to producer demand and throughput volume was specifically addressed by ATCO Pipelines and certain interveners. The Board will apply the criteria from the preceding section to the specific arguments raised with respect to the demand and throughput volume components of the producer revenue forecast.

Views of the Applicant

ATCO Pipelines argued that deferral accounts were not appropriate in the present circumstances with respect to the 2003/2004 producer revenue forecast. ATCO Pipelines argued that revenue forecasts were not beyond its control, and that forecasting was not the problem. ATCO submitted that the comparison of the 2001 and 2002 actual to forecast producer revenue from the 2001/2002 ATCO Pipelines South GRA demonstrated that it could forecast accurately. Further, ATCO Pipelines stated:

> In terms of asking how much of the 2003 revenue was assured and our answer that virtually all of it was assured, putting a deferred account on that doesn't – doesn't significantly reduce our risk. I mean, I'm not saying there's no risk on revenues but there's a lot bigger risks out there; and so what you're trying to do is put a Band-Aid on the wrong problem in our mind. The real problem is the level playing field issues, not the unpredictability of revenue.[68]

ATCO Pipelines argued that interveners were recommending the imposition of deferral accounts suggesting that this would reduce ATCO Pipelines' risk. ATCO Pipelines submitted the use of deferral accounts with respect to producer revenue would not necessarily lead to that result.

ATCO Pipelines submitted that most of ATCO Pipelines' producer revenues were under contracted demand and therefore not impacted by volume variances. Further ATCO Pipelines submitted that interruptible and overrun volumes were, overall, not of significant impact. ATCO Pipelines also stated that it had off-setting factors with respect to revenue from industrials and producers, that led to very accurate forecasts compared with actual amounts.

[68] Tr., p. 314, lines 10-18

ATCO Pipelines stated that a demand deferral account would not have any major impact on ATCO Pipelines' business risk. ATCO Pipelines suggested that based on the evidence and the above discussion regarding the appropriateness of deferral accounts, a demand deferral account was not appropriate in the circumstances.

ATCO Pipelines stated that a volume deferral account would not have any major impact on ATCO Pipelines 's business risk. ATCO Pipelines argued that CAPP's recommendation for a volume deferral account did not reflect the fact that most of ATCO Pipelines' revenues were under contracted demand and therefore not impacted by volume variances.[69] ATCO Pipelines argued that a volume deferral account would not remove any significant risk for ATCO Pipelines.

ATCO Pipelines submitted that the variability of the producer revenue forecast due to changes in natural gas prices was not significant. ATCO Pipelines stated that "...even though we have some interplay between the higher gas prices for some short term interruptible and the potential for industrial market shutdown, [ATCO Pipelines] still [prefers] to have the incentive in place because we think that serves both parties very well.[70]"

ATCO Pipelines replied to the AUMA/EDM/CG argument regarding the use of revenue deferral accounts. ATCO Pipelines argued the AUMA/EDM/CG ignored ATCO Pipelines' evidence that illustrated that production decline was less of a concern than price competition. ATCO Pipelines also submitted that any additional capacity available because of throughput decreases would be limited by the availability of exchange capacity. ATCO Pipelines stated that although AUMA/EDM/CG recommend the use of revenue deferral accounts, AUMA/EDM/CG did not support the recommendation with any evidence. ATCO Pipelines argued AUMA/EDM/CG chose to ignore the evidence and based their recommendation on general propositions, absent evidential support.

ATCO Pipelines also disagreed with AUMA/EDM/CG suggestion that forecast throughput decreases would free up transmission capacity and allow ATCO Pipelines to capture windfall revenue. ATCO Pipelines argued that suggestion ignored the evidence respecting ATCO Pipelines' lack of exchange capacity, which resulted in high exchange fees and was driving the contract terminations.

ATCO Pipelines argued that AUMA/EDM/CG's recommendation that revenue deferral accounts would somehow put ATCO Pipelines on an equal footing with NGTL ignored the evidence on the differences between NGTL and ATCO Pipelines.

ATCO Pipelines replied to the Calgary argument that the use of revenue deferral accounts was the fairest method for ATCO Pipelines and the ratepayers. ATCO Pipelines argued that Calgary's argument should be dismissed as ATCO Pipelines' revenue forecast was accurate and well supported by the evidence. ATCO Pipelines submitted it provided the forecast information based on its judgment of bypassed contract demand.

69 Information response – AUMA/EDM/AP.7
70 Tr., p. 953

ATCO Pipelines concluded that the Board has been supportive of prospective rate making and the efficiencies that arose from an absence of deferral accounts. ATCO Pipelines submitted that it was unnecessary for the Board to depart from its historical practice.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG submitted there were compelling reasons to support a Board decision directing ATCO Pipelines to institute revenue deferral accounts for the 2003 and 2004 test years. AUMA/EDM/CG stated they were not making the recommendation as a permanent remedy for forecasting uncertainty. Rather, in the particular circumstances prevailing in the 2003 and 2004 test years, AUMA/EDM/CG argued that revenue deferral accounts were clearly the best option, for the following reasons:

- For the first time in the history of Alberta, overall production decline occurred in 2002. It was too early to place any reliance on the continuation of this decline trend as projected by ATCO Pipelines, particularly when ATCO Pipelines did not take into account recent significant commodity price increases nor did ATCO Pipelines do any long term studies to support the continuation of this trend in its service areas.
- The competitive situation between ATCO Pipelines and NGTL was very much in play with the Board proactively taking the position of endeavoring to resolve these competitive issues. It was impossible to predict the outcome of this process, but it was unreasonable to assume the degree of negative impact forecast by ATCO Pipelines.
- Given ATCO Pipelines was forecasting significant producer throughput decreases relative to present 2002 levels, it followed that transmission physical infrastructure presently in place would be sufficient to handle higher production levels. If production was sustained at a significantly higher level than forecast by ATCO Pipelines, it was unlikely any significant additional capital investment would be required to service new production. Accordingly, if significant non-forecast increases in production occurred, it would create a large windfall gain to ATCO Pipelines given there would very likely be little cost involved in obtaining the additional revenue.
- In any event, even if ATCO Pipelines was required to build additional capital facilities not forecast in the present Application, ATCO Pipelines was free to make the case upon disposition of the increased production revenues accruing in a deferral account that certain of those revenues should be awarded to ATCO Pipelines to compensate ATCO Pipelines for the cost of service of additional non forecast capital facilities.
- Deferral accounts for producer revenue were a well-established and accepted mechanism on NGTL, were supported by producers on that system and were being recommended by CAPP for ATCO Pipelines as well. To the extent ATCO Pipelines contended it wished to be responsive to its customers, why would ATCO Pipelines not agree to a deferral account to put itself in a similar position to its principal competitor (NGTL)?

Calgary

Calgary recommended that deferral accounts be used for interruptible, overrun and short-term firm service revenues. Calgary argued that revenue deferral accounts protected both ATCO Pipelines and ratepayers from uncertainty. Calgary submitted that, in this case, the protection

would primarily be to ratepayers, as ATCO Pipelines appeared to have under-forecast producer revenue.

CAPP

CAPP submitted that ATCO Pipelines should be required to use firm service demand and throughput volume revenue deferral accounts, similar to those used by NGTL. CAPP argued that customers rather than ATCO Pipelines should be exposed to the risk associated with revenue forecasts. CAPP suggested that ATCO Pipelines was merely attempting to avoid revenue deferral accounts and under-forecast producer revenue as a way to earn higher returns than awarded by the Board.

Views of the Board

The Board evaluated the use of firm service demand and throughput volume revenue deferral accounts using the suggested criteria from the previous section. The Board considered the argument of ATCO Pipelines and interveners using those criteria as follows:

Materiality of the Forecast Amount
The Board notes there was little disagreement among parties that the producer revenue forecast is a material amount. However, ATCO Pipelines and interveners disagreed significantly regarding the appropriate amount of the producer revenue forecast with respect to firm service demand and throughput volume.

Uncertainty Regarding the Accuracy and Ability to Forecast the Amount
The Board notes that ATCO Pipelines argued it was able to accurately forecast revenue as demonstrated by the 2001/2002 ATCO Pipelines South GRA. The Board also notes that ATCO Pipelines submitted that firm service demand revenues were substantially certain for 2003, and that there were off-setting factors with respect to interruptible and overrun amounts that enabled ATCO Pipelines to forecast revenue with a high degree of certainty. ATCO Pipelines stated that natural gas prices did not greatly impact its forecasts for firm service producer revenue. However, the Board notes that interveners strongly disagreed with ATCO Pipelines regarding the accuracy of the producer revenue forecast and ATCO Pipelines' ability to forecast the amount. The Board notes interveners' argument that revenue deferral accounts would protect both ATCO Pipelines and ratepayers in the event the producer revenue forecast was significantly different from the actual amount.

Whether or Not the Factors Affecting the Forecast are Beyond the Utility's Control
The Board notes there were several factors affecting the producer revenue forecast, and that certain of those factors were beyond ATCO Pipelines' control. The Board notes that ATCO Pipelines referred to price competition, contract utilization and production declines (all factors beyond the utility's control) as factors affecting the forecast, however ATCO Pipelines appeared to be confident the producer revenue forecast was reasonable. Notwithstanding, the Board notes that interveners disagreed with ATCO Pipelines' ability to address the impact of those factors beyond its control.

Whether or Not the Utility is Typically at Risk with Respect to the Forecast Amount
The Board notes that the Board has typically avoided the use of deferral accounts for 'at-risk' amounts. The Board has generally accepted that there are benefits associated with the prospective test year whereby the utility is incented to 'beat' the forecast. The Board also notes

that there is a possibility that the use of deferral accounts could lead to swings in rates and inter-generational inequity. The Board notes ATCO Pipelines' suggestion that, if throughput declines as customers go to NGTL, the rates would climb via the deferral accounts, and that this could exacerbate the rate difference and incent more customers onto NGTL. However, the Board notes that interveners wanted full deferral of producer revenues, and that the risk of de-contracting and any associated revenue shortfall related to the deferral account is the customers' responsibility, not ATCO Pipelines' responsibility. The Board also notes that interveners submitted that ATCO Pipelines should be similar to NGTL regarding the use of revenue deferral accounts.

The Board considers that the producer revenue forecast is certainly material, and that, notwithstanding the Board's preference to avoid the use of deferral accounts when possible, the Board's past practice with respect to deferral accounts would not preclude the Board from using deferral accounts with respect to firm service demand and throughput volume producer revenue in this instance. Ultimately, the Board considers that the determining factors in this instance relate to the Board's assessment of ATCO Pipelines' ability to accurately forecast producer revenues, in light of the significant decrease forecast by ATCO Pipelines due to price competition, contract utilization and production declines. As indicated in the next Section of this Decision, the Board believes there is some attraction to using revenue deferral accounts in this case, rather than attempting to adjust ATCO Pipelines' forecast of producer revenues. However, owing to potential negative impacts which may arise for this utility through the use of deferral accounts, including rate fluctuations and intergenerational inequity, on balance in this case, the Board's preference is to avoid the use of deferral accounts when there is a suitable alternative and reasonable adjustments to the forecast can be made. These adjustments are addressed below.

7.3 Producer Revenue Forecasts

7.3.1 Firm Service Demand & Interruptible/Overrun Revenue Forecasts

The Board will address the forecast of the firm service demand and throughput volume revenue amounts together. The Board notes that the factors affecting ATCO Pipelines' producer revenue forecast could potentially impact each of these types of producer revenue.

Views of the Applicant

ATCO Pipelines forecast producer revenue of $53,315,000 in 2003 and $42,868,000 in 2004 compared to the 2002 actuals of $62,072,000.

ATCO Pipelines argued the Board should approve its producer revenue forecast rather than approving revenue deferral accounts as advocated by interveners. ATCO Pipelines submitted that it has forecast revenues with a high degree of accuracy and that no adjustment should be made to the ATCO Pipelines forecasts on the basis of higher current natural gas prices.[71]

ATCO Pipelines argued that extensive information was provided regarding the details of the producer revenue forecast. ATCO Pipelines submitted that detailed historical and forecast billing determinants and volumes supporting the revenue forecasts were provided. ATCO Pipelines also submitted that a comprehensive discussion and review of the reasons for contract demand terminations and the receipt points where the terminations were occurring was provided. ATCO

[71] Information response – BR.AP-44(c)

Pipelines provided information that illustrated the forecast contract demand terminations were occurring due to production declines, contract utilization, and price competition.[72]

ATCO Pipelines acknowledged that actual amounts might vary from the forecast, however ATCO Pipelines argued that there were offsetting factors in its forecast related to changes in the price of natural gas. ATCO Pipelines submitted that virtually all of its 2003 revenue was assured as most of ATCO Pipelines' revenues were under contracted demand, were based on discussions with producers, and were not impacted by volume variances. ATCO Pipelines submitted that the 2004 forecast was based on a combination of discussions with customers and an analysis of trends relating to actual contract demand levels. ATCO Pipelines acknowledged that the 2004 forecast amount was conservative. ATCO Pipelines argued that the real problem was the level playing field issues, not the unpredictability of revenues.

ATCO Pipelines provided information related to the 16 receipt stations that were also connected to NGTL. The table below summarized ATCO Pipelines daily receipts flow and station capacity[73].

Table 29. Capacity at Dually Connected Receipt Points

Dually Connected Receipt Points	ATCO Station Capacity (TJ/day)	Dec. 2002 Daily Flow (TJ/day)	Jan. 2003 Daily Flow (TJ/day)	Feb. 2003 Daily Flow (TJ/day)
North Daily Flow	802	388	391	383
South Daily Flow	293	170	148	142

ATCO Pipelines also provided information related to meetings held with customers regarding 2003 exchange fees on February 10, 2003 and March 3, 2003 at which ATCO Pipelines provided updated EDA forecasts for 2003[74]. The March 3, 2003 forecast included a 100 TJ/day (20%) decrease in firm receipts in the South in 2003 and a 170 TJ/day (17%) decrease in firm receipts in the North in 2003.

ATCO Pipelines argued its evidence illustrated that production decline was less of a concern than price competition. ATCO Pipelines also suggested that any additional capacity available because of throughput decreases would be limited by the availability of exchange capacity.

ATCO Pipelines disagreed with the AUMA/EDM/CG submission that ATCO Pipelines' new rate design would mitigate the price competition with NGTL. ATCO Pipelines argued there was no evidence that the new rate design would have that impact or that NGTL would not react in a competitive manner. ATCO Pipelines submitted that NGTL focused its efforts during the proceeding on Phase II issues and competition.

ATCO Pipelines replied to the AUMA/EDM/CG submission that the Jasper NOP Upgrade-Peers to Marlborough would enable 25 TJ of new producer receipts for export. ATCO Pipelines argued

72 Information response – BR.AP-38
73 Information response – CAL.AP-63(d)
74 Information response – CAPP.AP-21

that all Jasper NOP Upgrade – Peers to Marlborough incremental revenues were already included in ATCO Pipelines' revenue forecast as new demand.[75]

ATCO Pipelines also replied to the AUMA/EDM/CG submission that there should be a 50% reduction to the forecast decline in revenues. ATCO Pipelines argued the AUMA/EDM/CG submission was based on flawed assumptions. ATCO Pipelines also argued the 50% reduction was an unrealistic recommendation given that most of the 2003 declines were known when ATCO Pipelines prepared the forecast. ATCO Pipelines concluded that no intervener provided evidence that disputed the reasonableness of ATCO Pipelines' revenue forecast. ATCO Pipelines submitted that its forecast should therefore be approved as filed.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG submitted that the issue of the steep decline forecast by ATCO Pipelines for producer revenue was one of the most contentious and widely canvassed in the proceeding. AUMA/EDM/CG argued the issue was important since it not only formed a significant portion of the total revenue forecast of ATCO Pipelines, but was also argued as a basis for the assessment of increased business risk by ATCO Pipelines. AUMA/EDM/CG submitted that ATCO Pipelines was being overly pessimistic in its forecast of reduced producer revenue.

AUMA/EDM/CG argued that an adjustment to the producer revenue forecast was not the preferred alternative of AUMA/EDM/CG. The preferred alternative was a revenue deferral account. AUMA/EDM/CG submitted that would obviate the need for the Board determining a specific producer revenue forecast. However, it recognized that the Board might not agree with AUMA/EDM/CG that a producer revenue deferral account is appropriate. Accordingly, in Argument, AUMA/EDM/CG provided its recommendations concerning the producer revenue forecast the Board should adopt in lieu of a deferral account approach.

AUMA/EDM/CG noted that the ATCO Pipelines forecast of producer revenue of $53,315,000 in 2003 and $42,868,000 in 2004 represented a reduction of 14.1% in 2003 and a reduction of 30.5% in 2004 compared to the 2002 actuals of $62,072,000.

AUMA/EDM/CG also noted that ATCO Pipelines provided a breakdown of the reasons for the reduction in volumetric contract demand for both APN and APS in 2003 and 2004, summarized by GJ of demand, in the following table[76]:

Table 30. Declines in Volumetric Contract Demand

	APN				APS			
Year	Prod. Decline	CD Utilizat.	Price Compet.	Totals	Prod. Decline	CD Utilizat.	Price Compet.	Totals
2003	130,556	21,375	42,159	194,090	46,362	30	53,800	100,462
2004	76,500	0	30,000	106,500	24,000	0	82,000	106,000
Totals	207,056	21,375	72,159	300,590	70,362	300	145,800	206,462
% of Totals	68.9	7.1	24.0		34.0	0.1	65.8	

[75] Information response – BR.AP-37
[76] Based on Information Response – BR.AP-38

AUMA/EDM/CG submitted that approximately 60% of the total forecast volumetric contract reduction in aggregate over the two years occurred in APN (300,590) as compared with APS (206,462). Since the contract demand rate was higher in APN ($3.50/GJ vs. $2.25/GJ in APS) the respective %ages weighted for firm revenue impact were 70% for APN and 30% for APS.[77]

AUMA/EDM/CG suggested the primary reason for the volumetric contract reduction was production declines in overall terms and was particularly important in APN. (68.9% in APN, 34.0% APS, 55 % % for the combined system) The second most important reason was price competition (24.0% in APN, 65.8% in APS, 41% for the combined system).

AUMA/EDM/CG submitted the contract reductions accounted for approximately 90% of the decline in the total producer revenue forecast in both 2003 and 2004. AUMA/EDM/CG also submitted that ATCO Pipelines forecast a decline in interruptible and overrun revenue of similar proportions to the decline in firm revenue.

AUMA/EDM/CG stated there were two fundamental reasons why ATCO Pipelines was overstating the amount of producer revenue decline.

First, with regard to production declines, ATCO Pipelines relied too heavily on the trend in the last two years and advice received from producers and failed to recognize appropriately the improvement in supply in 2003 and 2004 resulting from high commodity prices. AUMA/EDM/CG argued that ATCO Pipelines was reluctant to agree to the obvious in that higher gas prices lead to increased revenue and noted ATCO Pipelines' argument that increased interruptible revenue could be offset by reductions in firm demand. AUMA/EDM/CG also suggested the substantive evidence of Mr. Liddle with respect to business risk demonstrated the rate of producer throughput decline forecast by ATCO Pipelines was too severe.[78] Mr. Liddle submitted that the declines in basin productivity did not in any way support the very large reductions in producer deliveries forecast by ATCO Pipelines in the 2003/2004 period. The NEB December 2002 Short-Term Natural Gas Deliverability report projects a 4% decline over the period 2001 to 2004.

Second, the projected reduction was expected to occur because of price competition. However, AUMA/EDM/CG submitted that ATCO Pipelines assumed it had no ability to try to counter the price competition from NGTL. AUMA/EDM/CG noted that ATCO Pipelines would be filing its Phase II Application in September 2003, and it was reasonable to expect ATCO Pipelines would propose a new rate design to improve its competitive position with respect to NGTL. Notwithstanding any new rate design would not be approved until later in 2004, it could be expected that ATCO Pipelines would seek to obtain interim approval of new rates. AUMA/EDM/CG argued that, as a minimum, producers could be expected to reconsider notices of contract termination if there was an expectation the competitive position of ATCO Pipelines would improve in the relatively near future.

AUMA/EDM/CG suggested that an example of ATCO Pipelines taking actions to remain competitive with NGTL was the proposal for the Jasper NOP Upgrade-Peers to Marlborough. If approved by the Board, the addition would increase the capacity for firm delivery at the Alliance

[77] The weighted revenue impact is determined for APN as 60% X $3.50/ ((60% x $3.50) + (40% X $2.25)) which calculates to 70%. Similarly the APS calculation results in a weighted revenue impact of 30 %.

[78] Evidence of Bob Liddle, p. 9-13

Hinton interconnect by 25 TJ/day thereby offering additional opportunity for producers to use the ATCO Pipelines system for deliveries to the export market.

For these reasons, AUMA/EDM/CG recommended the Board adopt a producer revenue forecast reducing the amount of decline projected by ATCO Pipelines for both APN and APS by 50% of the amounts shown on Tables 5.1-2 and 5.1-3 of the Application. AUMA/EDM/CG did not endeavor to attribute the increased forecast revenues to specific producer revenue categories. AUMA/EDM/CG submitted the expected increase in throughput would occur from a combination of less firm demand reduction and greater overrun/interruptible revenue as compared to ATCO Pipelines' forecast.

Table 31. Recommended Reductions to Forecast of Producer Revenue – ATCO Pipelines vs. AUMA/EDM/CG ($000)

	APN		APS	
Year	APN Application	AUMA/EDM/CG	APS Application	AUMA/EDM/CG
2002	46,738	46,738	15,334	15,334
2003	40,876	43,807	12,439	13,869
2004	34,890	40,814	7,978	11,656

As stated at the outset of this section, a reduction in the producer revenue forecast was not the preferred alternative of AUMA/EDM/CG. The preferred alternative was a deferral account.

Calgary

Calgary argued the Board should approve the use of revenue deferral accounts with respect to ATCO Pipelines' forecast of producer revenue, as discussed in previous sections. Calgary did not propose an alternative to the ATCO Pipelines producer revenue forecast.

CAPP

CAPP argued the Board should approve the use of revenue deferral accounts with respect to ATCO Pipelines' forecast of producer revenue, as discussed in previous sections. CAPP did not propose an alternative to the ATCO Pipelines producer revenue forecast.

Views of the Board

As noted in the previous section, the Board considers that in light of the level of disagreement between ATCO Pipelines and interveners regarding the producer revenue forecast and the possible use of revenue deferral accounts, the criteria that will be considered in this instance relate to the Board's assessment of ATCO Pipelines' ability to accurately forecast producer revenues and the nature of the factors affecting the forecast.

The Board notes that ATCO Pipelines provided historical and forecast billing determinants, contract terminations, and interruptible/overrun volumes for APN, APS and total ATCO Pipelines. The contract termination information was separated according to the factor ATCO Pipelines considered as the cause for the termination (i.e. production decline, CD utilization, price competition), and according to the type of receipt station (i.e. dual or single connected). The Board also notes the commentary provided by ATCO Pipelines in support of the producer revenue forecast.

The Board notes that ATCO Pipelines attributed contract terminations at dual connected stations almost entirely to price competition, whereas contract terminations at single connected stations were primarily due to production declines. The Board also notes that declines in contract demand due to CD utilization could be due to both price competition and production declines.

The Board notes that the disagreement as to the revenue forecast between ATCO Pipelines and interveners, particularly AUMA/EDM/CG, was primarily due to the level of decline in contract demand due to terminations and what interveners argued was a pessimistic view by ATCO Pipelines regarding the amount the decline in contract demand would be mitigated by renewals, new services, and interruptible service. The Board notes that Calgary and CAPP preferred the use of revenue deferral accounts to address the possible forecast variance rather than providing an alternative forecast. The Board also notes that the AUMA/EDM/CG alternate forecast of producer revenue was not the AUMA/EDM/CG's preferred option either.

The Board has carefully considered the evidence on this issue and agrees with interveners that ATCO Pipelines' forecast was overly conservative, particularly with respect to the forecast of terminations due to production declines, and the degree to which CD utilization and terminations due to price competition would impact interruptible volumes.

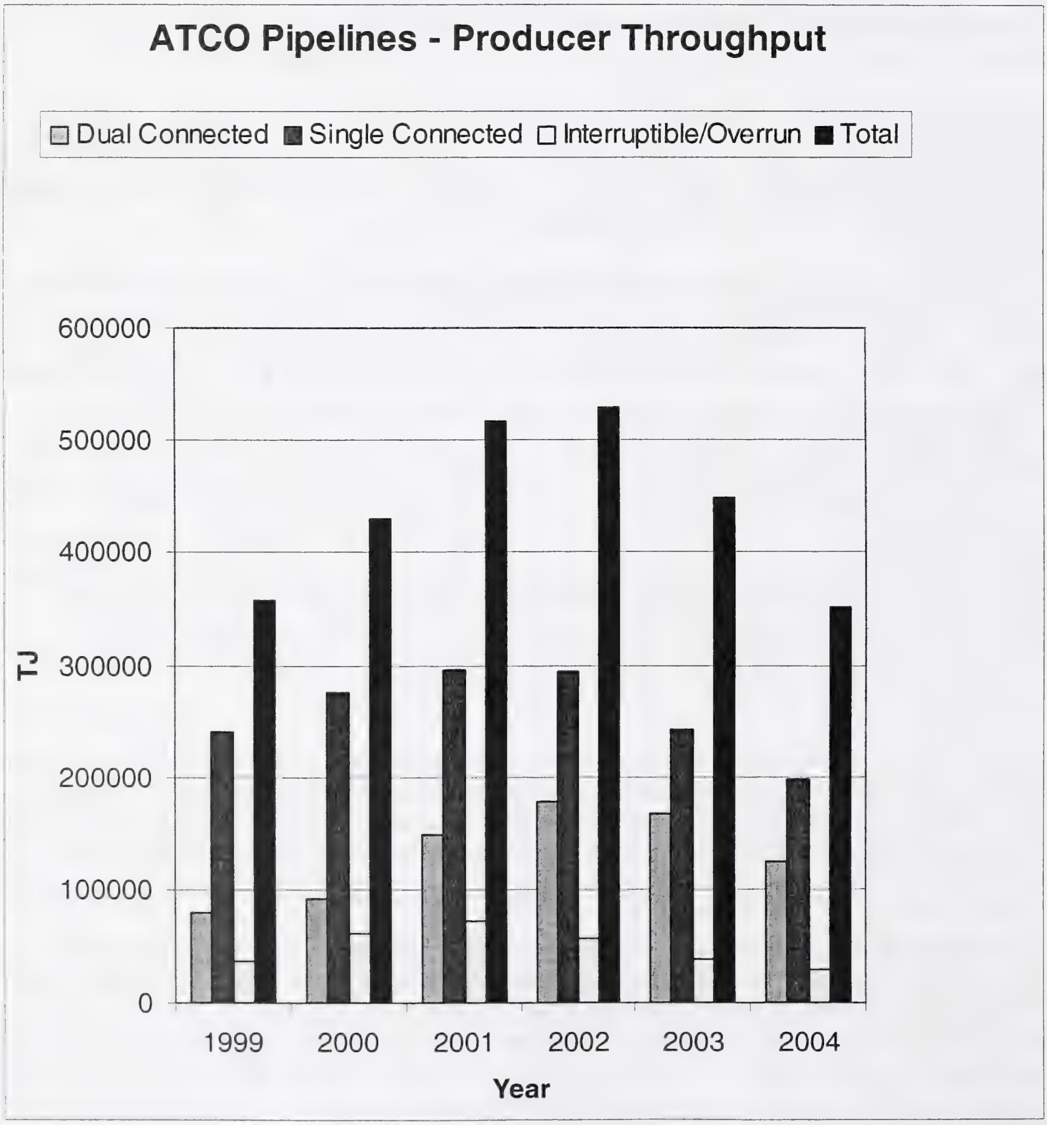
The Board notes that contract demand at dual connected stations has increased significantly in the past few years, however, the Board notes ATCO Pipelines' submission that a significant amount of its contract demand is short term in nature and able to terminate in the next one to two years. The Board considered AUMA/EDM/CG's suggestion regarding ATCO Pipelines' ability to mitigate some of the contract terminations at dual connected stations via ATCO Pipelines' new rate design. However, the Board accepts ATCO Pipelines' argument that customers at dual connected stations might not be convinced to reconsider their termination or renew their contract on the basis of an applied for rate design, or new interim rates. The Board also notes that pricing between ATCO Pipelines and NGTL at dual connected stations has changed in comparison with previous years. The Board considers those customers that have an option might choose instead to flow their volumes on an interruptible basis or use an alternate pipeline. The Board does not accept ATCO Pipelines' argument that exchange capacity might not be available should customers decide to flow on an interruptible basis rather than on a contract demand basis. The Board does not believe ATCO Pipelines demonstrated this adequately.

The Board does not find ATCO Pipelines' evidence with respect to contract terminations due to production declines to be fully persuasive. The Board notes that there is no study to support the level of declines forecast by ATCO Pipelines in its service area, only an analysis based on trends and informal feedback from producers and customers that cannot be verified or tested. The Board notes that the evidence of Mr. Liddle refers to a forecast production decline for the basin of 4% over the period 2001 to 2004 (or an average of one % per year), whereas ATCO Pipelines is forecasting significant firm demand revenue declines at single connected stations in the range of 14% for 2003 and 20% for 2004, and significant interruptible revenue declines for both 2003 and 2004, for both APN and APS in the ranges of 30% for 2003 and 22% for 2004. The Board agrees with AUMA/EDM/CG that ATCO Pipelines relied too heavily on the trend in the last two years.

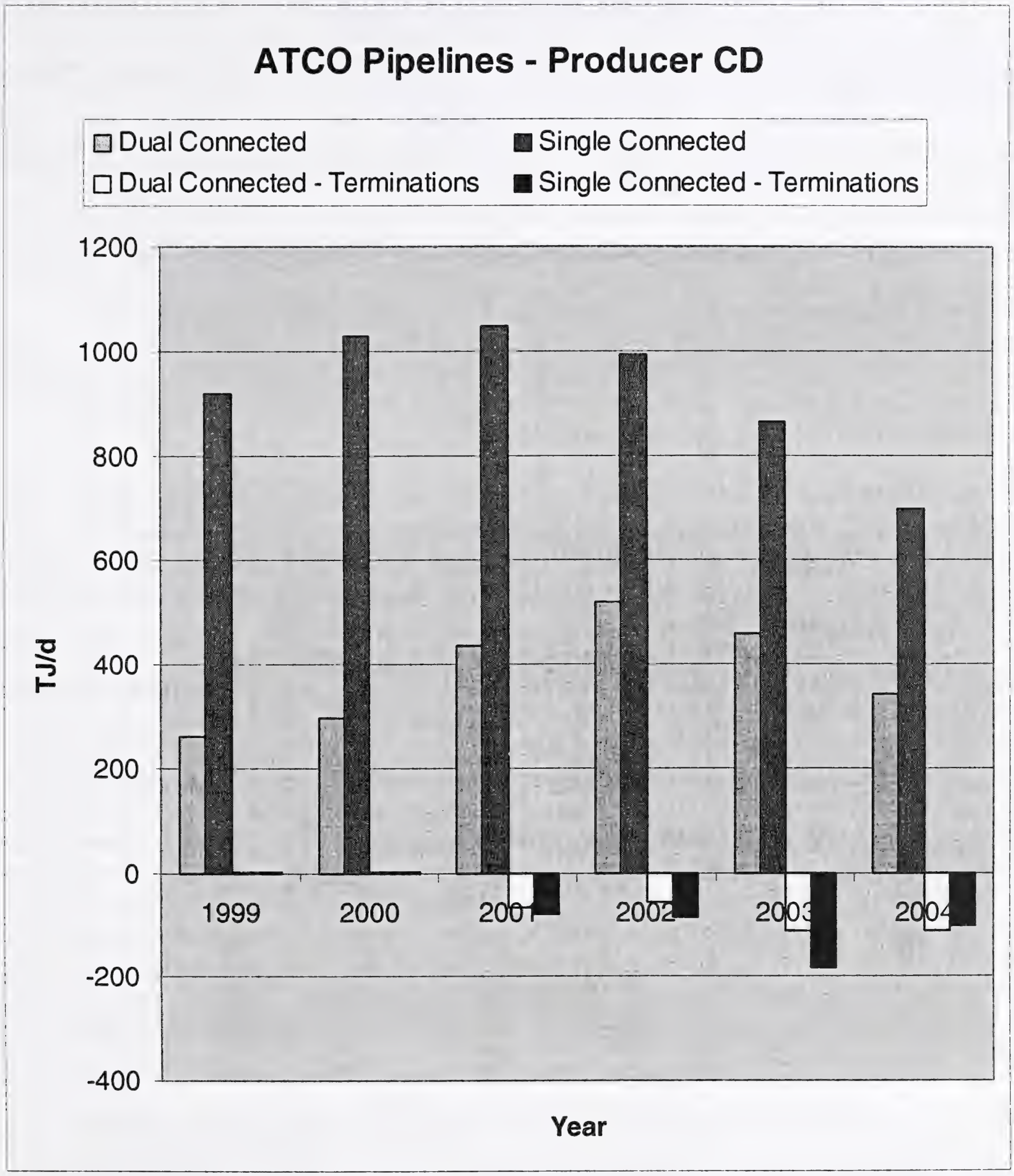
Further, the Board considers that the historical information provided by ATCO Pipelines with respect to contract demand and throughput at single connected stations does not support the level of production decline forecast by ATCO Pipelines. For example, the 'extensive information'

provided by ATCO with respect to contract terminations does not fully explain the changes to contract demand experienced on the ATCO Pipelines system since 1999. The Board notes that contract demand at both dual and single connected stations increased during 1999-2001 and remained relatively flat or experienced a modest decline in 2002, yet there were significant contract terminations in each of those years. Accordingly, the Board is not convinced that ATCO Pipelines has forecast sufficient contract renewals or switches to interruptible service during the 2003/2004 forecast period.

The Board has graphed the throughput and contract demand information provide by ATCO Pipelines.[79]



[79] Based on BR.AP-37, BR.AP-38, BR.AP-45, and AUMA/EDM.AP-7



The Board believes that the above graphs illustrate in a general fashion some of the issues and concerns relating to the Applicant's revenue forecast, and its credibility, particularly in terms of the steep declines in volumes and demand for the test years, compared to prior years when a number of the same market fundamentals applied to the Applicant.

The Board considers that there is some attraction to using revenue deferral accounts in this case, rather than attempting to adjust ATCO Pipelines' forecast of producer revenues. However, on balance, in this case the Board's preference is to avoid the use of deferral accounts when there is a suitable alternative, particularly given some of the potential negative impacts of deferral

accounts on ATCO Pipelines, such as future rate fluctuations at unsustainable levels and the potential consequences thereof to a competitive pipeline of its size and position in the market. Therefore, the Board prefers to address the revenue forecast and to adjust it to reasonable levels. The Board has considered ATCO Pipelines' forecast and has found it to be overly conservative as previously stated.

The Board has evaluated various methods by which it could adjust the producer revenue forecast. The Board considered the general method proposed by AUMA/EDM/CG and found it to be a somewhat arbitrary compromise, notwithstanding that the AUMA/EDM/CG might have conducted significant analysis prior to including the alternate forecast in its argument.

The Board considered other general methods of adjusting the producer revenue forecast, including the use of various rates of decline from the 2002 actual contract demand and throughput amounts. The Board found those methods to be unsatisfactory, because they did not properly reflect the different impacts of price competition at the dual connected stations and production declines at the single connected stations.

The Board considered applying uniform adjustments to overall throughput as opposed to focusing on changes to contract demand and interruptible volumes. The Board found those methods to be unsatisfactory as well. The Board is not convinced that the impact of price competition would be properly reflected if the Board assumed the same rates of decline at both single and dual connected stations.

The Board considered applying different adjustments to dual and single connected stations and to interruptible throughput amounts. The Board finds these methods to be more sensible and consistent with ATCO Pipelines' view that the impacts of production declines, CD utilization, and price competition should be reflected separately in the forecast. After evaluating the evidence, the Board concludes that the adjustment that appropriately reflects production declines, CD utilization, and price competition is as follows. The Board accepts ATCO Pipelines forecast of dual connected CD. In terms of single connected CD and IT throughput, the Board notes that the decline in single CD was 7% in APN and was 2.2% in APS from 2001-2002, whereas the forecast decline from the NEB Report for the Western Canadian Sedimentary Basin was 4% between 2001 and 2004. With respect to IT throughput, the Board does not consider that ATCO has demonstrated any factor that would explain the forecast declines. The Board considers it reasonable to adjust the forecast rate of decline to 2.5% for each of the test years for single connected CD and IT throughput.

The Board considers that the foregoing adjustment to ATCO Pipelines' producer revenue forecast is reasonable. The Board accepts that there could be a decrease in ATCO Pipelines' producer revenues in 2003 and 2004; however, the Board is not prepared to accept ATCO Pipelines' forecast. Therefore the Board has adjusted the ATCO Pipelines revenue forecast as follows:

Table 32. Board Approved Forecast of Producer Revenue[80]($000)

Year	APN APN Application	APN Per Board	APS APS Application	APS Per Board
2002	46,738	46,738	15,334	15,334
2003	40,876	43,996	12,439	14,230
2004	34,890	42,615	7,978	11,243

Year	ATCO Pipelines Total ATCO Pipelines Application	ATCO Pipelines Total Per Board
2002	62,072	62,072
2003	53,315	58,226
2004	42,868	53,858

7.3.2 Affiliate Producer Revenue

Views of the Applicant

ATCO Pipelines forecast producer affiliate revenue, including ATCO Midstream receipt revenue, to decrease from $1,380,000 in 2002, to $693,000 in 2003 and to $624,000 in 2004. ATCO Pipelines submitted the decrease was due service terminations in 2003, and production declines in 2004.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG submitted the producer affiliate revenue component was relatively minor compared to the producer revenue forecast. AUMA/EDM/CG submitted, on the basis of its recommended reductions in forecast producer revenue on an aggregate basis, producer affiliate revenue reductions were captured in the aggregate estimate.

Views of the Board

The Board has separately adjusted ATCO Pipelines' forecast of producer firm service demand and interruptible/overrun throughput revenue in the previous section. The Board does not consider further adjustment to the affiliate producer revenue necessary and therefore approves ATCO Pipelines' forecast of affiliate producer revenue as applied for.

7.3.3 Producer Facilities Revenue

Views of the Applicant

ATCO Pipelines forecast producer facilities revenue to decline from $44,000 in 2002, to $6,000 in 2003 and to zero in 2004 due to customers completing their obligations with respect to specific facilities built for their use.

80 The Board approved amounts for APN and ATCO Pipelines Total for 2003 and 2004 are reduced by the amount forecast separately for producer affiliate revenue and producer facility revenue.

Views of the Interveners

Interveners did not specifically address producer facilities revenue in argument.

Views of the Board

The Board approves ATCO Pipelines' forecast of producer facilities revenue as applied for.

7.4 Non-Standard Agreements

ATCO Pipelines requested approval of seven new non-standard agreements, in addition to the four existing non-standard agreements. ATCO Pipelines and IGCAA recommended the agreements should be approved as applied for, whereas other interveners disagreed. In addition to the consideration of the new non-standard agreements, parties addressed what they considered to be the appropriate criteria for the acceptance of non-standard agreements, the appropriate term for such contracts, and the use of a deferral account with respect to shortfalls that could arise with respect to the recovery of incremental capital, operating expenses and UFG.

7.4.1 Appropriate Criteria for the Acceptance of Non-Standard Service Agreements

Views of the Applicant

ATCO Pipelines argued that non-standard contracts delivered benefits from retaining or attracting load to the ATCO Pipelines system. ATCO Pipelines submitted that its ability to enter into such arrangements was established in numerous prior Board Decisions, including Decision 2001-97.

ATCO Pipelines submitted that the Board rejected the requirement that ATCO Pipelines should be subject to the same terms as the NGTL load retention service (LRS). ATCO Pipelines submitted that the Board approved ATCO Pipelines' ability to enter into a non-standard contract, subject to shareholder risk, until the Board approved the non-standard contract in a subsequent review.

ATCO Pipelines suggested the Board's approval of a non-standard contract must be based on the facts, circumstances and issues that existed at the time the non-standard contract was entered into. ATCO Pipelines argued that the Board should not impute knowledge to a utility that the utility could not reasonably have at the time it entered into the contract, and that a prudence review should not be made on the basis of hindsight.

ATCO Pipelines argued that general criteria for establishing the prudence of entering into a non-standard agreement had been established for ATCO Pipelines in numerous Board Decisions. ATCO Pipelines submitted that the Board considered whether (i) a competitive alternative existed which would result in a loss of the customer without the non-standard agreement, and (ii) the remaining customers would realize a net benefit.

ATCO Pipelines submitted that each non-standard contract was unique, and that it might not be possible to satisfy additional criteria when a non-standard contract was assessed. ATCO Pipelines submitted that the additional criteria suggested by Mr. Liddle might not be achieved in every instance. ATCO Pipelines also submitted that it was not appropriate to adopt the same criteria used to assess standard investments. ATCO Pipelines argued that certain projects might have indirect revenue that would not be incorporated into the standard investment test. ATCO

Pipelines also argued that some of the issues related to non-standard contracts should be addressed in a Phase II proceeding.

ATCO Pipelines submitted that the flexibility of the non-standard contract was essential, and that it was the only tool that ATCO Pipelines had in order to compete with NGTL. ATCO Pipelines submitted that avoiding the upfront regulatory process and timing associated with pre-approval was one of the benefits of a non-standard contract for ATCO Pipelines. ATCO Pipelines submitted that AUMA/EDM/CG recognized the need for ATCO Pipelines to have flexibility.

ATCO Pipelines disagreed with AUMA/EDM/CG regarding the treatment of a non-standard contract as a package. ATCO Pipelines argued that it was not appropriate to adjust a portion(s) of the contract, or truncate the approved term of the contract.

ATCO Pipelines argued that if the Board had a concern around the implementation of a non-standard contract prior to a full GRA review, the Board could review the non-standard contract pursuant to the filing sent to the Board prior to implementation of the non-standard contract.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG submitted that the fundamental principles supporting the use of non-standard contracts are that a competitive alternative existed at the time and that the incremental revenues exceeded the incremental costs, as have been established in prior Board decisions. AUMA/EDM/CG also noted that the Board considered the indirect benefit associated with the EDA in Decision 2001-97.

AUMA/EDM/CG recommended that the Board include Mr. Liddle's recommendation that, where applicable, all non-standard contracts contain provisions that allowed the contracts to adjust over the term of the agreement in response to changes in the competitive alternative pipeline's rates or the rates of ATCO Pipelines itself. AUMA/EDM/CG submitted that such adjustment was very important in the current environment where it seemed virtually certain the rates for service on both the ATCO Pipelines and NGTL systems were likely to change as a result of upcoming Phase II proceedings for both companies.

AUMA/EDM/CG noted that there was discussion during the proceeding of the guidelines used in determining approval of LRS rates on the NGTL system and whether those guidelines should be applicable to approval of non-standard contracts on the ATCO Pipelines system. AUMA/EDM/CG submitted that the Board should not directly transfer to ATCO Pipelines the guidelines developed for the specific circumstances of the NGTL system. AUMA/EDM/CG suggested the non-standard contracts brought forward for approval by ATCO Pipelines had a greater variety of circumstances (e.g. Valleyview or TransGas contracts) that were not in response to a specific bypass threat. Therefore, AUMA/EDM/CG stated it was necessary to maintain a degree of flexibility in the application of guidelines to approval of the ATCO Pipelines non-standard contracts.

AUMA/EDM/CG was also concerned whether or not ATCO Pipelines relied only on existing price levels for key forecast assumptions (notably gas prices) in its projections of costs and benefits over a long term. AUMA/EDM/CG recommended that the Board should require ATCO Pipelines to demonstrate in its detailed evaluations that it used its best available forecast for

future values of key variables. AUMA/EDM/CG replied that they had no difficulty with the portion of Decision 2001-110 quoted by ATCO Pipelines in Argument; however, AUMA/EDM/CG suggested that ATCO Pipelines could not abdicate itself from the exercise of good judgment, including the reasonable forecasting of inputs affecting the non-standard contract.

Calgary

Calgary generally agreed with the principles outlined in Mr. Liddle's evidence, being:

- A competitive alternative for the customer exists and can be demonstrated and quantified;
- A discounted toll provides benefits to all customers. With respect to marginal costs, marginal costs should include the full amount of the UFG Rider D (as it varies from time to time);
- The non-standard contract should be a load retention contract;
- There should be assurance of incremental capital cost recovery; and
- If the contract is not for load retention but for new services, there should be a definite calculation of the cost of alternative service, either NGTL or the cost of the customer building its own pipeline, together with all owning and operating costs associated with them.

CAPP

CAPP acknowledged that ATCO Pipelines used non-standard contracts without the benefit of prior Board approval, and that ATCO Pipelines was at risk should the Board not approve a contract pursuant to a subsequent Board review of the contract. CAPP disagreed with the AUMA/EDM/CG proposal to recover any deficiency related to a non-standard contract through the EDA account. CAPP argued that non-standard contracts benefited all customers by adding or retaining markets on the ATCO Pipelines system.

NGTL

NGTL stated that it was appropriate for utilities to use innovative rates and services to respond to competitive bypass threats, provided that such action was constrained by appropriate rate design criteria and that interested and affected parties were provided an opportunity to review such rates and services before implementation.

NGTL submitted that the Board had considered and implemented the use of specific criteria to govern the use of non-standard rates and services by other utilities on several occasions.[81] NGTL encouraged the Board to similarly determine and establish comprehensive criteria in this proceeding to judge the acceptability of each non-standard agreement proposed in the Application, and any non-standard agreement that ATCO might propose in the future. NGTL did not advocate a specific list of criteria that the Board should apply in adjudicating ATCO Pipelines' non-standard agreements. However, NGTL suggested that those criteria should not unduly advantage or disadvantage ATCO Pipelines' competitive position relative to NGTL.

[81] Decisions E95062 and U97096

NGTL submitted that non-standard contracts had become commonplace on the ATCO Pipelines system and that ATCO Pipelines used them to attract and retain volumes frequently in the past two years. NGTL submitted that it was concerned about the recent proliferation of non-standard agreements, and about ATCO Pipelines' apparent reliance on them as a response to actual or perceived competition. NGTL submitted that many of the agreements were exclusive, long-term arrangements that by their very nature were intended to preclude competition for many years.

NGTL stated that it did not question ATCO Pipelines' ability to independently contract with customers for services and rates that were outside its existing, approved tariff. NGTL submitted that ATCO Pipelines did not require Board approval to enter into these agreements, subject, of course, to specific legislative limitations. However, NGTL was opposed to ATCO Pipelines' practice of implementing those agreements prior to interested parties and the Board having an appropriate opportunity to review, and as required, adjudicate them. NGTL believed ATCO Pipelines' practice was unfair to parties that might be affected by the agreements.

NGTL submitted it had been ATCO Pipelines' practice to file non-standard agreements with the Board the day before it implemented the corresponding services and rates. NGTL also submitted that it understood the Board acknowledged the filings subject to a prudence review at ATCO Pipelines' next GRA.

NGTL suggested that the Board should expressly direct ATCO Pipelines to obtain Board approval of any future non-standard terms and conditions of service and non-standard rates before ATCO Pipelines implements them. NGTL recommended that ATCO Pipelines should be required to file any new proposed non-standard agreements a reasonable period of time before implementation to allow interested parties and the Board an appropriate opportunity to understand, and as required, to test the merits of the agreement before service commenced. NGTL submitted that the Board and stakeholders would not require the timeframe of 6-12 months suggested by ATCO Pipelines. NGTL submitted that NGTL had in the past always obtained prior Board approval of its non-standard service and rate offerings before implementing them.[82]

NGTL also argued that it became more difficult with the passage of time to unwind an agreement, particularly when the utility and its customers structured corollary business arrangements around them. NGTL suggested a review of non-standard contracts prior to implementation could be consistent with an objective of leveling the competitive playing field.

NGTL argued that if the Board endorsed ATCO Pipelines continuing its practice of seeking post implementation approval of non-standard contracts, then the Board should clearly state whether the practice was unique to ATCO Pipelines or if it was equally available to other utilities. NGTL argued an ability to offer new services at new rates without prior Board and stakeholder review was a significant competitive tool, and one that should be available to other utilities under comparable circumstances.

Views of the Board

The Board acknowledges that the Board has accepted ATCO Pipelines' use of non-standard contracts in previous Decisions. The Board also notes that interveners have generally accepted

[82] Decisions 2002-043 and U97096, and Order U99042, approving LRS, LRS-2, and LRS-3 services

their use, subject to the consideration of certain additional criteria beyond those addressed by ATCO Pipelines. However, the Board notes that the frequency of their use by ATCO Pipelines and the potential magnitude of their impact on ATCO Pipelines' revenue raises some potential issues for the Board to consider.

The Board notes NGTL's suggestion that there appeared to be different standards for different utilities regulated by the Board regarding the ability to use non-standard contracts. The Board also notes suggestions by ATCO Pipelines, NGTL, CAPP and AUMA/EDM/CG that the use of non-standard contracts is a significant competitive tool. The Board agrees that the ability to use non-standard contracts can be a significant competitive tool with respect to the retention and attraction of customers, and that the ability of utilities regulated by the Board to use non-standard contracts should be reviewed.

The Board notes that there were varying criteria with respect to the evaluation of non-standard contracts proposed for the Board's consideration in this proceeding. The Board also notes that parties also proposed various regulatory methods by which non-standard contracts could be reviewed and approved.

The Board considers that its practice with respect to bypass and load retention situations has been relatively consistent, notwithstanding that each case is evaluated on its own merits. The Board has typically used criteria similar to those referred to by NGTL from its own LRS offerings.

Similarly, the Board's practice with respect to the competition between utilities or other competitive alternatives for the provision of incremental service to an existing customer, or service to a new customer, has been relatively consistent. The Board has generally considered whether or not there would be an unnecessary proliferation of facilities, and has evaluated the options from a least cost perspective, similar to the criteria used for bypass and load retention situations.

The Board considers that the use of non-standard contracts in the past was not intended to be preferential to any one utility, or to become the 'normal' practice, particularly when the dollar impact is potentially significant and long-term. The Board acknowledges that the use of non-standard contracts has been attractive from an efficiency and convenience perspective, particularly when the dollar impact is not significant, and where the impacts are short-term. The Board also acknowledges that there are trade-offs associated with the use of non-standard contracts. The Board notes the potential for regulatory efficiencies related to the Board's prudence review at the next GRA, versus the time required for a pre-approval proceeding. The Board also notes the potential for securing a benefit related to the attraction or retention of a customer that might otherwise be lost without the use of non-standard contracts. Further, there could be a potential trade-off between the utility's acceptance of the risk of offering the non-standard contract prior to a Board review, versus the ability to conduct a meaningful prudence review and unwind a non-standard contract after it has been in operation for some time.

The Board considers that the use of non-standard contracts is not in dispute, but rather the specific criteria to be applied in each case and whether or not the utility requires approval of the non-standard contract prior to the implementation of the contract. The Board considers that the criteria for non-standard contracts should generally align with the criteria previously noted for bypass/load retention situations and situations where there is competition between utilities or

other competitive alternatives for the provision of incremental service to an existing customer, or service to a new customer. The Board believes that the four LRS criteria enunciated in Decision U97096 and used since by the Board in a number of cases, should be used in bypass/load retention situations, and that the utility's standard rates should be used when incremental or new service is being provided unless the utility can convince that Board that different criteria and rates should be considered. The Board also agrees with Calgary that the principles outlined in Mr. Liddle's evidence are valuable, and expects that these principles may be included in the future assessment of non-standard contracts using the four LRS criteria as the initial bases for analysis, and in the assessment of incremental or new service as applicable.

The Board notes that ATCO Pipelines considers that it should be able to act aggressively to attract or maintain load, and that it would do so subject to shareholder risk until Board approval is granted pursuant to a subsequent review. The Board agrees that ATCO Pipelines should be able to be able to attract and maintain load; however, the Board is concerned with the use of non-standard contracts without an appropriate opportunity to review the contract prior to implementation, particularly when the situation involves incremental capital and operating expenses. The Board will be concerned with non-standard contract offers when the arrangements do not satisfy the standard investment criteria, or the four LRS criteria previously noted with respect to incremental/new service or to bypass/load retention.

The Board considers that the ability to conduct a prudence review of a non-standard contract after the fact is not the preferred method of reviewing such an arrangement, compared to a review prior to implementation of the non-standard contract. The burden of proof regarding the merit of the non-standard contract should lie with the utility as a positive test at the time it is being considered, rather than on interveners and the Board as a negative test after the fact, and with the constraint that 'hindsight' tests not be employed, particularly when the non-standard contract has been in operation for some time. The Board finds that it is preferable for the utility to demonstrate its case on a prospective basis using the 'knowledge' it has at the time it enters into the non-standard contract, rather than placing the onus on interveners and the Board to 'not impute knowledge to a utility that the utility could not reasonably have know at the time of the decision to enter the agreement' as argued by ATCO Pipelines.

Therefore, the Board directs that ATCO Pipelines to file any future non-standard contracts with the Board prior to implementation, allowing sufficient time for interveners and the Board to conduct an appropriate review. The Board considers that this requirement applies to all utilities that it regulates.

7.4.2 Appropriate Approval Term for Non-Standard Contracts

Views of the Applicant

ATCO Pipelines requested approval of the full term of each non-standard agreement that was filed in the Application. ATCO Pipelines submitted that the prudence of each non-standard agreement should be determined based on the facts, circumstances and issues that existed at the time the agreements were negotiated. ATCO Pipelines argued it would be unfair and inappropriate to review agreements using changed facts, circumstances and issues existing at a later date.

ATCO Pipelines argued that, to the extent that re-openers or termination rights existed in ATCO Pipelines' favour, the prudence of ATCO Pipelines with respect to actions taken or not taken

under those rights must also be determined based on the facts, circumstances and issues that exist at the time the re-opener or termination right was valid.

ATCO Pipelines disagreed with AUMA/EDM/CG that the Board should consider truncating the approval of certain non-standard contracts. ATCO Pipelines argued that while it endeavored to assure the recovery of incremental capital, for example, it might not be possible to achieve all the desired principles of non-standard contracts in every circumstance.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG supported, in principle, the concept of utilizing non-standard contracts to retain load over the long term on the ATCO Pipelines system that would otherwise be lost in the absence of a non-standard contract. Therefore, as a general principle, AUMA/EDM/CG submitted they supported the approval of non-standard contracts for the long term. However, AUMA/EDM/CG argued that the support of long-term contracts was based on two critical qualifiers.

AUMA/EDM/CG suggested long-term approval should be granted to those contracts with mechanisms that allowed responsiveness to changes in the competitive alternatives, and to those contracts containing a mechanism guaranteeing recovery of incremental capital cost.

NGTL

NGTL submitted that ATCO Pipelines' use of non-standard services and rates might be symptomatic of more fundamental, underlying rate design issues on the ATCO system. NGTL submitted that these were Phase II issues that would be addressed in ATCO Pipelines' next Phase II proceeding. However, NGTL argued the Board should be cognizant of this fundamental problem when it considered whether, and for what terms, the Board should approve the proposed non-standard contracts in this proceeding.

Views of the Board

The Board considers that the term of the non-standard contracts, including the re-openers and termination rights that might exist at ATCO Pipelines' discretion, should be evaluated at the time the contract was entered into, or at the time the re-opener or termination right is valid. The Board is aware, as noted by AUMA/EDM/CG, that there are factors that must be considered with respect to the appropriate term, therefore the Board will make that determination for each contract based on the specific circumstances in existence at the time the contract was entered into, rather than making that determination on a generic basis in this Section of the Decision.

7.4.3 Use of Deferral Accounts for Non-Standard Revenue Forecasts

Views of the Applicant

ATCO Pipelines submitted that it was not in favor of the EDA mechanism, or the deferral account mechanism proposed by AUMA/EDM/CG to eliminate the variability on forecasted revenue with respect to non-standard contracts. ATCO Pipelines argued that the issue of which customer classes received both the benefits and costs of the non-standard contracts should be addressed in the Phase II application. Furthermore, ATCO Pipelines disagreed with AUMA/EDM/CG's suggestion that there was an overall 'cost' to customers as, without the non-

standard contracts, ATCO Pipelines would not be receiving the benefit of revenues from industrial and producer customers.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG noted that Mr. Liddle recommended that where revenues under a non-standard contract were based on variable factors beyond ATCO Pipelines' ability to control (e.g. the DGP mechanism), it would be reasonable to set up a deferral account for those revenues. Mr. Liddle subsequently provided his rationale and the mechanism to be used for the deferral account. Mr. Liddle proposed that surpluses or deficiencies relative to the forecast made by ATCO Pipelines for a non-standard contract would be accrued and be subject to approval for disposition at the next GRA.

Mr. Liddle also recommended an alternate mechanism for covering the deficiencies in revenues under nonstandard contracts. Mr. Liddle proposed that a charge could be made to the EDA account to ensure that any shortfall, between actual revenues received under a non-standard contract and the cost of service for additional facilities needed to service that non-standard contract, was recovered from the benefits to the EDA arising from non-standard contracts. AUMA/EDM/CG argued, that if accepted, the recommendation would ensure all customers were kept whole with respect to non-standard contract revenues and costs.

Of the two mechanisms proposed by Mr. Liddle, AUMA/EDM/CG recommended the EDA method as the most effective and fair way to ensure that all customers were kept whole for costs created by non-standard contracts.

CAPP

CAPP disagreed with the AUMA/EDM/CG proposal to allocate any shortfall associated with non-standard revenue to the EDA. CAPP argued that revenue received pursuant to a non-standard contract was a benefit to all customers.

Views of the Board

The Board notes that ATCO Pipelines and other interveners did not support the AUMA/EDM/CG proposed deferral account mechanisms with respect to non-standard accounts. While the Board agrees that a deferral account mechanism has some appeal, whether by way of a separate account or through the EDA, the Board's preference is to regulate without the use of deferral accounts except where unique circumstances require their use. Otherwise, the deferral account mechanism simply defers the impact and disposition of any shortfall that might arise with respect to a non-standard contract. The Board will address the impact(s) of each non-standard contract proposed by ATCO Pipelines on its own merit in this Decision. In future, the Board considers that impacts will be addressed for non-standard contracts in the pre-approval process. Therefore, any need for deferral accounts should be diminished.

7.4.4 ATCO Power – Valleyview Non-Standard Contract

Views of the Applicant

ATCO Pipelines submitted that the ATCO Power non-standard agreement filed in this proceeding was different than the other non-standard agreements in that it was a long-term, cost

of service based agreement. ATCO Pipelines submitted the agreement provided for full recovery of capital and that the pipeline services the Valleyview power plant operated independently of the remainder of the system.

ATCO Pipelines submitted that the non-standard agreement resulted in a cumulative net present value revenue requirement of $1.02 million, and a cumulative net present value of revenue of $1.27 million. Therefore, the ATCO Power agreement provided a cumulative net present value benefit to other customers of $0.25 million and should be approved for its full term.

ATCO Pipelines suggested that Calgary was the only party that recommended the ATCO Power contract not be approved as filed. ATCO Pipelines replied to Calgary's submission that ATCO Pipelines did not provide the competitive options available to ATCO Power and/or that ATCO Pipelines did not provide the cost to ATCO Power of building its own facility. ATCO Pipelines advised that the cost for constructing the pipeline was stated as $800,000 in the Application.

ATCO Pipelines also noted that Mr. Liddle recommended approval of the contract. ATCO Pipelines argued that the Board should not give any weight to Calgary's argument regarding the potential precedent being set regarding the avoidance of an ATCO Pipelines' meter station.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG noted this was an affiliate transaction and that particular care must be taken to ensure the affiliate customer did not receive any advantage that would not accrue to a stand-alone arms length party.

AUMA/EDM/CG noted that ATCO Pipelines did not present any information with respect to the competitive options, if any, available to ATCO Power. In his evidence, Mr. Liddle calculated the cost resulting from use of a standard contract rate and found that the annual cost would be $415,920, or almost four times greater than the levelized cost of service used as the cost basis in the non-standard contract.

On the basis of that analysis, Mr. Liddle indicated he was satisfied an arm's length party would have either built their own facility or similarly requested a special rate from ATCO Pipelines. Given that full cost recovery was assured and that other utility customers were kept whole, Mr. Liddle recommended approval of the contract and AUMA/EDM/CG concurred.

Calgary

Calgary generally accepted the recommendations of Mr. Liddle, however, Calgary suggested the ATCO Power contract should not be approved until such time as ATCO Pipelines provided the competitive options that were available for ATCO Power and/or ATCO Power's cost of building its own facility. Further, Calgary argued there seemed to be a precedent being set with respect to avoiding an ATCO Pipelines meter station and accepting an NGTL meter station as a custody transfer measurement point. It was not clear whether other customers were offered a similar type arrangement.

IGCAA

IGCAA submitted that all non-standard agreements should be approved for their entire term.

Views of the Board

The Board approves this contract as filed. However, the Board considers that Calgary raised a valid issue with respect to the selection of the custody transfer measurement point. The Board directs ATCO Pipelines in its Refiling to clarify its policy regarding the installation of metering for delivery service.

7.4.5 Shell Canada Ltd. – Fort Saskatchewan Non-Standard Contract

Views of the Applicant

ATCO Pipelines submitted that competitive pressures in the Fort Saskatchewan area were acknowledged frequently in this proceeding. At the time when this contract was negotiated (fall 2001) NGTL had an application before the Board for a pipeline to serve Agrium, Dow and Sherritt.

ATCO Pipelines submitted that the pricing agreed to in this non-standard contract provided for a 2.0 cents/GJ demand rate (on a contract demand basis) plus a fixed 0.452% UFG/Fuel component until late 2008, and periodic re-openers based primarily on a DGP pricing mechanism plus 1.0 cent/GJ thereafter. ATCO Pipelines stated that the 2.0 cents/GJ demand rate was competitive with the 1.9 cents/GJ NGTL DGP option. ATCO Pipelines noted that the NGTL Intra-Alberta delivery toll was zero in the fall of 2001, and that NGTL had filed a cost of service study with the Board that suggested an approximate 5.0 cents/GJ Intra-Alberta cost of service. Expected revenue was therefore limited to the 5.3 cents/GJ standard rate subsequent to 2008.

ATCO Pipelines submitted that the cumulative net present value of the revenue stream was calculated at $10.6 million. The project was forecast to require $4.5 million of incremental capital for customer specific facilities with a worst case $6.05 million provided for in the agreement. The cumulative revenue requirement using the base case (original case) of $4.5 million of capital was $5.3 million and using the high case of $6.05 million was $7.1 million. ATCO Pipelines submitted that the base case cumulative revenue benefit exceeds the cumulative cost by $5.3 million ($3.5 million in the high capital case).

ATCO Pipelines noted that Mr. Liddle expressed a concern that a rate of 3.0 cents/GJ would be required for the post-2008 term to breakeven, and that if a 2.0 cents/GJ rate were to continue past 2008, then a shortfall of $2 million could occur. ATCO Pipelines noted that Mr. Liddle's concern was based on the high capital case of $6.05 million versus the $4.5 million base case. ATCO Pipelines suggested that it was also evident that Mr. Liddle's concern was related to price sensitivity as opposed to a forecast of post-2008 rates.

ATCO Pipelines argued that the probability of the 2008 renegotiated price being below 3.0 cents/GJ was extremely remote. ATCO Pipelines submitted that the Shell price was based on the price of the competitive alternative plus 1 cent/GJ. ATCO Pipelines argued that if no competitive alternative existed, the Shell contract price would be redetermined to equal the average Dow-Agrium rates, or that if no such rates existed, the lowest published rate for service into Fort Saskatchewan would be applicable. ATCO Pipelines argued that the probability of the Shell contract price extending beyond 2008 at a rate below Mr. Liddle's 3.0 cents/GJ breakeven price was remote.

ATCO Pipelines replied to the suggestion that there was the potential for a shortfall or surplus accruing under the contract resulting from the fixed UFG amount varying from the actual Rider D. ATCO Pipelines disagreed with respect to Calgary's suggested condition that Rider D be used for UFG, rather than the fixed component. ATCO Pipelines argued that Calgary did not present any explanation or evidence to support the recommendation. ATCO Pipelines argued there was no evidence quantifying UFG deficiencies or surpluses, other than that presented by ATCO Pipelines.

ATCO Pipelines also disagreed with AUMA/EDM/CG's two suggested remedies with respect to any shortfall that might arise due to the Shell non-standard contract.

In summary, ATCO Pipelines argued that the Shell non-standard agreement was forecast to provide significant benefits to customers. ATCO Pipelines submitted that the agreement was prudent and requested approval of the agreement as filed for its full term.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG stated that the Shell non-standard contract was the most detailed and robust in the sense of having comprehensive directions with respect to price renegotiation in 2008. However, Mr. Liddle expressed concern that until the results of the contract renegotiation were known in 2008, it could not be assured the contract would generate sufficient revenues to cover the incremental capital and operating costs on a present worth basis. Mr. Liddle also suggested there was the potential that a shortfall or surplus to accrue under the contract, should the fixed UFG amount vary from the actual Rider D values.

Mr. Liddle suggested two possible remedies. First, any shortfalls in revenue on an ongoing basis should be charged to the EDA, ensuring all utility customers were kept whole. Second, the Board should approve the Shell contract only until 2008 when the results of the price renegotiation would be known. If, at that time, the price renegotiation was higher than the 3 cents/GJ breakeven level identified by Mr. Liddle, or ATCO Pipelines demonstrated some other mechanism that ensured customers were kept whole, then presumably the contract could be approved for the balance of its term.

AUMA/EDM/CG preferred the first remedy proposed by Mr. Liddle, since all parties agreed the EDA benefits from retention of the Shell load and cost recovery would be assured on a current basis rather than waiting for the uncertain outcome of the 2008 renegotiation.

Calgary

Calgary generally accepted the recommendations of Mr. Liddle. Calgary suggested that the Shell non-standard contract should be approved, subject to a provision for the potential shortfall of revenue in years prior to 2008, and the use of Rider D for UFG.

IGCAA

IGCAA submitted that all non-standard agreements should be approved for their entire term.

Views of the Board

The Board notes that AUMA/EDM/CG and Calgary recommended that any shortfall between the fixed UFG and Fuel rate of 0.452% and Rider D should be subject to either a charge to the EDA or a deferral account. The Board notes that the fixed rate will vary from the actual Rider D over time, however, the Board considers that the fixed rate of 0.452% is reasonable over the term of the contract.

The Board notes that AUMA/EDM/CG and Calgary also recommended alternatives whereby any revenue shortfall associated with the other components of the non-standard contract could be deferred or recovered from the EDA. The Board also notes that AUMA/EDM/CG suggested the Board could approve the term of the contract until 2008 after which the price is re-determined according to the pricing mechanism in the contract.

The Board notes that the revenue collected from the demand rate does not guarantee the recovery of incremental capital, unless it is above a breakeven rate of approximately 3.0 cents/GJ after 2008. Further, the Board notes that the contract contains a facilities buyout upon termination. The Board further notes that at a demand rate in the 2 to 3 cents/GJ range, there is little contribution toward incremental O&M, or ATCO Pipelines' other mainline costs. However, all parties acknowledged there was a positive impact on the EDA and associated producer revenues resulting from the retention of Shell on the ATCO Pipelines system.

The Board could approve the contract until 2008 as suggested by AUMA/EDM/CG, however the Board finds that such an approval merely defers dealing with the issue. While the Board notes that the revenue shortfall, if any, would be easier to quantify at that time, the issue regarding the allocation of that shortfall would undoubtedly be contentious. The Board also notes that there would also have been benefits to ATCO Pipelines and other customers during the interim period associated with the EDA that would be equally difficult to quantify and allocate. The Board considers that a review of the contract in 2008, with an assignment of shortfalls at that time, would be unacceptable.

The Board prefers to deal with this contract in this Decision based on the information that would have been available to ATCO Pipelines at the time it entered into the contract. The Board notes that ATCO Pipelines and other customers were faced with the undesirable possibility of losing a large market from the ATCO Pipelines system. The Board finds that ATCO Pipelines mitigated the potential loss of market situation and that the ATCO Pipelines system should benefit from the retention of Shell as a delivery customer. The Board considers that all customers should receive an appropriate share of the benefit, pursuant to the determination of rates in the upcoming Phase II proceeding. Therefore, the Board approves the Shell non-standard contract for its full term as filed.

7.4.6 Agrium Inc. – Fort Saskatchewan and Redwater Non-Standard Contract

Views of the Applicant

ATCO Pipelines submitted the Agrium non-standard contract was entered into at the time that NGTL had its Fort Saskatchewan pipeline application[83] before the Board. ATCO Pipelines submitted that by entering into the agreement with Agrium for both the Fort Saskatchewan and

[83] Application No. 1245440

Redwater facilities, ATCO Pipelines has retained Agrium as a customer until such time as Agrium permanently shuts down the facilities at these locations or ATCO Pipelines elects not to match pricing under the DGP mechanism. ATCO Pipelines submitted the DGP mechanism was based upon the principle that the delivered price of gas at Agrium's plant gate was equivalent regardless of what pipeline served its facilities. The mechanism took into account UFG and fuel, market price differential, any intra-Alberta delivery toll on NGTL and ATCO Pipelines' toll. ATCO Pipelines stated that at the time of entering into the agreement, the ATCO Pipelines toll was established at 1.9 cents/GJ.

ATCO Pipelines argued that contrary to the evidence filed by Mr. Liddle, the Agrium agreement did not include incremental capital investment. ATCO Pipelines submitted that Mr. Liddle acknowledged in cross-examination that no incremental capital investment was required. ATCO Pipelines clarified that the facilities were not new, rather they related to the un-depreciated cost of assets carried forward into the non-standard contract. ATCO Pipelines disagreed with the AUMA/EDM/CG submission that provision should be made for any shortfall associated with the DGP mechanism to be charged to the EDA to ensure cost recovery.

ATCO Pipelines noted that AUMA/EDM/CG and Calgary suggested the potential for an under-recovery of UFG costs. ATCO Pipelines replied to AUMA/EDM/CG's suggested charge to the EDA for any shortfall associated with UFG, and to Calgary's suggested use of Rider D for UFG. ATCO Pipelines argued that no quantifiable evidence was put forth to substantiate any shortfall, and that the only quantifiable evidence was that presented by ATCO Pipelines.

ATCO Pipelines submitted that it sought approval of the non-standard contract, however, as the agreement had an annual re-opener, ATCO Pipelines would be open to review in each GRA regarding the prudence of making decisions with respect to the re-opener at that time. ATCO Pipelines stated:

> So on a go-forward basis, we believe that the agreement reached at the time of negotiating was appropriate, and that if at three years from now we're sitting here having a discussion about why we did not terminate the contract, that's a different issue at that moment in time. But the agreement itself provides those mechanisms to ATCO Pipelines and it benefits all customers.[84]

ATCO Pipelines argued that the ability to conduct a prudence examination at a future date rendered the concerns of Mr. Liddle moot. ATCO Pipelines submitted that overall, the agreement entered into with Agrium provided a benefit to all customers. In addition to the benefits of retaining Agrium and the attendant revenues ensured ATCO Pipelines of a long-term market to retain producer revenues that benefited all customers and the EDA. ATCO Pipelines submited that the non-standard contract entered into with Agrium was prudent and requested approval as filed.

Views of the Interveners

AUMA/EDM/CG

Mr. Liddle recommended that the Board approve the Agrium non-standard contract subject to the Board also approving the use of the EDA mechanism, whereby potential revenue shortfalls

[84] ATCO Pipelines Argument, p. 71

would be charged against the EDA. Alternatively, Mr. Liddle recommended the Board approve the contract, but only for a five-year term with a direction to ATCO Pipelines to attempt to negotiate a minimum annual payment that would ensure a reasonable breakeven point.

AUMA/EDM/CG submitted that the contract contained a variable DGP mechanism that ensured responsiveness to prevailing market conditions. However, AUMA/EDM/CG stated that a lack of any floor price meant there was no guarantee of the minimum price of 1.1 cents/GJ necessary to assure a breakeven with the incremental cost of service over the life of the contract. While Mr. Liddle's opinion was that the necessary minimum of 1.1 cents/GJ would probably be achieved through the operation of the DGP mechanism, Mr. Liddle recommended provision be made for any shortfall to be charged against the EDA. AUMA/EDM/CG submitted the use of the EDA mechanism would also ensure a cost recovery of any under recovery of UFG costs if, and when, Rider D exceeds 0.452%.

AUMA/EDM/CG preferred Mr. Liddle's recommended EDA mechanism as opposed to a limited five-year approval of the contract.

Calgary

Calgary generally accepted the recommendations of Mr. Liddle. Calgary suggested that the Agrium non-standard contract should be approved, subject to the use of a deferral account for dealing with variations in the DGP and the use of Rider D with respect to UFG instead of the ATCO Pipelines method (which recovers the lesser of 0.452% or Rider D).

IGCAA

IGCAA submitted that all non-standard agreements should be approved for their entire term.

Views of the Board

The Board notes that AUMA/EDM/CG and Calgary recommended any shortfall between the fixed UFG and Fuel rate of 0.452% and Rider D should be subject to either a charge to the EDA or a deferral account. The Board notes that the fixed rate will vary from the actual Rider D over time, however the Board considers that the fixed rate of 0.452% is reasonable over the term of the contract, subject to the annual re-openers.

The Board notes that AUMA/EDM/CG and Calgary also recommended alternatives whereby any revenue shortfall associated with the DGP contract could be deferred or recovered from the EDA. The Board also notes that AUMA/EDM/CG suggested the Board could approve the contract for a term of five years with a direction to ATCO Pipelines to attempt to negotiate a minimum annual payment that would ensure a reasonable breakeven point.

The Board notes that the revenue collected from the demand rate does not guarantee the recovery of un-depreciated capital, however the forecast rate appeared to be sufficient based on information available at the time ATCO Pipelines entered into the contract with Agrium. Further, the Board notes that the contract contains a provision for facilities buyout on termination. The Board notes that there could also be a contribution toward incremental O&M, or ATCO Pipelines' other mainline costs. Parties also acknowledged there was a positive impact on the EDA and associated producer revenues resulting from the retention of Agrium on the ATCO Pipelines system.

The Board considers that it could approve the contract for five years as suggested by the AUMA/EDM/CG, however the Board finds that such an approval merely defers dealing with the issue. While the Board notes that the revenue shortfall, if any, would be easier to quantify at that time, the issue regarding the allocation of that shortfall would undoubtedly be contentious. The Board also notes that there would also have been benefits to ATCO Pipelines and other customers during that time associated with the EDA that would be equally difficult to quantify and allocate. The Board considers that a review of the contract in five years, with an assignment of shortfalls at that time, would be unacceptable.

The Board prefers to make a final determination on this contract in this Decision, based on the information that would have been available to ATCO Pipelines at the time it entered into the contract. The Board notes that ATCO Pipelines and other customers were faced with the undesirable possibility of losing a large market from the ATCO Pipelines system. The Board finds that ATCO Pipelines mitigated that situation and that the ATCO Pipelines system should benefit from the retention of Agrium as a delivery customer. The Board considers that all customers should receive an appropriate share of the benefit, pursuant to the determination of rates in the upcoming ATCO Pipelines Phase II proceeding.

The Board agrees with ATCO Pipelines that a review of its decisions made pursuant to re-openers in the contract will be subject to review in subsequent GRAs as required, at the time they are available to ATCO Pipelines for future test years.

Therefore, the Board approves the Agrium non-standard contract for its full term as filed.

7.4.7 Dow Chemical Canada Inc. – Fort Saskatchewan Non-Standard Contract

Views of the Applicant

ATCO Pipelines submitted that the Dow non-standard contract was entered into to secure the total and incremental Dow loads at the Fort Saskatchewan complex for a minimum term of 15 years. ATCO Pipelines submitted that the Dow non-standard contract followed the Board's Decision 2002-058 respecting NGTL's proposed Fort Saskatchewan pipeline application. ATCO Pipelines argued that although the NGTL Fort Saskatchewan application was denied, ATCO Pipelines believed then, and continued to believe, that a significant risk still existed that NGTL had firm plans to serve existing industrial market in the Fort Saskatchewan area.

ATCO Pipelines submitted that Dow's incremental natural gas requirements were 69 TJ/day for 2003. ATCO Pipelines stated that, in order to accommodate the incremental requirement, new facilities were required, as well as an additional pipeline to meet Dow's requested increase in security of supply. Accordingly, Dow committed to an annual minimum revenue charge to ensure that ATCO Pipelines received revenues for the facilities installed. ATCO Pipelines argued the non-standard contract provided an overall benefit to all customers because revenues would continue to be received from Dow, ATCO Pipelines maintained corresponding producer receipt revenues, and Dow provided contributions toward overall UFG.

ATCO Pipelines noted that all interveners recommended the approval of this agreement, and that only Calgary suggested the use of a deferral account, a position no longer being recommended by AUMA/EDM/CG.

ATCO Pipelines argued it had clearly identified the overall benefits of the long-term retention of Dow, and therefore submitted the non-standard contract was prudent. ATCO Pipelines requested approval of the contract as filed for its full term.

Views of the Interveners

AUMA/EDM/CG

This contract contains both a minimum DGP of 2 cents/GJ and a minimum annual payment of $717,000 ensuring cost recovery of incremental facilities. Further, the contract simply requires Dow to pay the Rider D UFG charge at whatever level exists from time to time. Therefore, there is no issue with short fall arising from UFG. Mr. Liddle recommends the contract be approved as filed and AUMA/EDM/CG agree with this recommendation.

Calgary

Calgary generally accepted the recommendations of Mr. Liddle, however Calgary suggested that a revenue deferral account be used with respect to any shortfalls that might arise based on the DGP.

IGCAA

IGCAA submitted that all non-standard agreements should be approved for their entire term.

Views of the Board

The Board notes that the contract incorporates Rider D, a minimum DGP of 2 cents/GJ, a minimum annual payment of $717,000, and a facilities buyout on termination. The Board notes that there could also be a contribution toward incremental O&M, or ATCO Pipelines' other mainline costs. Parties also acknowledged there was a positive impact on the EDA and associated producer revenues resulting from the retention of Dow on the ATCO Pipelines system.

The Board prefers to deal with this contract in this Decision based on the information that would have been available to ATCO Pipelines at the time it entered into the contract. The Board notes that ATCO Pipelines and other customers were faced with the undesirable possibility of losing a large market from the ATCO Pipelines system. The Board finds that ATCO Pipelines mitigated that situation and that the ATCO Pipelines system should benefit from the retention of Dow as a delivery customer. The Board considers that all customers should receive an appropriate share of the benefit, pursuant to the determination of rates in the upcoming Phase II proceeding. Therefore, the Board approves the Dow non-standard contract for its full term as filed.

7.4.8 Sherritt International Corp. – Fort Saskatchewan Non-Standard Contract

Views of the Applicant

ATCO Pipelines submitted that it entered into a long-term non-standard contract with Sherritt for service to the Fort Saskatchewan facility subsequent to the Board's Decision 2002-058 on NGTL's proposed Fort Saskatchewan pipeline application. ATCO Pipelines argued that although the NGTL Fort Saskatchewan application was denied, ATCO Pipelines believed then, and continued to believe, that a significant risk still existed that NGTL had firm plans to serve existing industrial market in the Fort Saskatchewan area.

ATCO Pipelines submitted that the non-standard contract was for a minimum period of ten years and a further period of five years, if not terminated after ten years. ATCO Pipelines noted that pricing under the non-standard contract was the DGP mechanism with a floor price of 3cents/GJ. ATCO Pipelines also noted that a minimum annual revenue charge of $132,000 was also included. ATCO Pipelines stated that no incremental facilities were required.

ATCO Pipelines noted that all interveners have recommended the approval of this agreement. ATCO Pipelines also noted that only Calgary suggested the use of a deferral account with respect to any revenue shortfall that might arise pursuant to the use of the DGP mechanism.

ATCO Pipelines argued that the long-term retention of the Sherritt load provided an overall benefit to all customers as revenues would continue to be received from Sherritt, ATCO Pipelines maintained corresponding producer receipt volumes, and Sherritt contributed toward overall UFG. ATCO Pipelines therefore submitted that the non-standard contract was prudent and should be approved as filed.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG noted that no incremental facilities were required to service this non-standard contract and that the contract contained a DGP mechanism with a floor price of 3 cents/GJ and a minimum annual payment of [$192,000.] AUMA/EDM/CG agreed that there should be a recovery of ongoing operating costs. AUMA/EDM/CG also noted that the Sherritt contract recovered UFG at Rider D levels ensuring no shortfall would occur relative to UFG. Mr. Liddle recommended the contract be approved and AUMA/EDM/CG agreed with the recommendation.

Calgary

Calgary generally accepted the recommendations of Mr. Liddle, however Calgary recommended that the Sherritt non-standard contract be approved subject to the use of a DGP revenue deferral account.

IGCAA

IGCAA submitted that all non-standard agreements should be approved for their entire term.

Views of the Board

The Board notes that the contract incorporates Rider D, a minimum DGP of 3 cents/GJ, and a minimum annual payment of $132,000. The Board notes that the Sherritt contract recovers UFG at Rider D levels ensuring no shortfall would occur relative to UFG and fuel. The Board considers there could also be a contribution toward incremental O&M or ATCO Pipelines' other mainline costs. The Board also considers there should be a positive impact on the EDA and associated producer revenues resulting from the retention of Sherritt on the ATCO Pipelines system.

The Board prefers to deal with this contract in this Decision based on the information that would have been available to ATCO Pipelines at the time it entered into the contract. The Board notes that ATCO Pipelines and other customers were faced with the undesirable possibility of losing a large market from the ATCO Pipelines system. The Board finds that ATCO Pipelines mitigated

that situation and that the ATCO Pipelines system should benefit from the retention of Sherritt as a delivery customer. The Board considers that all customers should receive an appropriate share of the benefit, pursuant to the determination of rates in the upcoming Phase II proceeding.

Therefore, the Board approves the Sherritt non-standard contract for its full term as filed.

7.4.9 TransGas Limited Non-Standard Contract

Views of the Applicant

ATCO Pipelines submitted that a non-standard contract was entered into with Many Islands Pipe Lines (Canada) Limited that provided for 15 TJ/day of firm service delivery transportation service at ATCO Pipelines' existing Devonia Lake delivery point. ATCO Pipelines indicated that the customer in the agreement is TransGas Limited (TransGas). ATCO Pipelines stated that other than the delivery point and delivery pressure, the terms and conditions of service were essentially the same as ATCO Pipelines' firm service delivery to Alliance.

ATCO Pipelines stated that the net benefit provided by the TransGas non-standard contract was that gas "must flow" off ATCO Pipelines' system. If TransGas did not flow the full nominated demand off ATCO Pipelines' system, TransGas was responsible for the charges incurred by ATCO Pipelines for any deficient quantities unloaded by ATCO Pipelines to the NGTL system. Hence, the EDA benefited from the 100% load factor market access contract. ATCO Pipelines noted that Mr. Liddle agreed the TransGas non-standard contract provided a positive contribution to the EDA.

ATCO Pipelines submitted that no capital costs were incurred to provide the service and full UFG/Fuel was provided in kind by TransGas. ATCO Pipelines stated that the non-standard contract could be terminated by either party upon twelve months' notice. ATCO Pipelines suggested that Mr. Liddle also recommended that the agreement be approved, subject to ATCO Pipelines establishing that this was truly an incremental load.

ATCO Pipelines disagreed with Mr. Liddle's characterization of the TransGas service as "free" gas service that could set a precedent for any party that could demonstrate the ability to take incremental summer gas off the ATCO Pipelines system. ATCO Pipelines argued that the toll charged to TransGas was consistent with the toll ATCO Pipelines charged for delivery to any interconnecting pipeline, including NGTL. ATCO Pipelines stated that it did not charge a toll for delivery to NGTL, only the UFG and fuel on delivery, consistent with Alliance and TransGas deliveries.

ATCO Pipelines also replied to NGTL's submission that the Board should defer consideration of the TransGas agreement to Phase II. ATCO Pipelines suggested that the sole basis of NGTL's requested delay was that ATCO Pipelines did not claim or provide evidence that TransGas had a competitive alternative to ATCO Pipelines' services. ATCO Pipelines submitted that NGTL's argument was unfounded and that the requested delay was simply the predictable action of a competitor.

ATCO Pipelines argued that it was clear that the TransGas non-standard agreement resulted in gas flowing to an alternate system rather than NGTL (thus displacing volumes flowing at an NGTL interconnect) and thus provided a significant benefit to the EDA. ATCO Pipelines submitted that:

> The TransGas contract was an opportunity to access a new market that we weren't currently accessing…[85]

ATCO Pipelines therefore submitted that its entry into this agreement was prudent and should be approved as filed.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG noted that the TransGas non-standard contract required no incremental facilities and that, other than UFG charges, was at no cost to TransGas. AUMA/EDM/CG submitted that the benefits from the contract related entirely to the positive impact on the EDA. Mr. Liddle recommended approval of the non-standard contract subject to the Board being satisfied the TransGas load was truly incremental to the ATCO Pipelines system and not simply displacing gas already being delivered to TransGas under another contract. AUMA/EDM/CG argued that since the benefit of the TransGas non-standard contract related entirely to the existence of the EDA, any approval of the contract should necessarily be term limited to the duration of the EDA mechanism.

Mr. Liddle also expressed concern that by offering the TransGas type of non-standard contract, characterized as "free" gas service, ATCO Pipelines had, in effect, established a precedent wherein any party that demonstrating the ability to take incremental summer gas could be similarly offered "free" gas service. AUMA/EDM/CG was concerned that it was often difficult to determine if load was truly incremental and would certainly not encourage the proliferation of that type of future rate making. AUMA/EDM/CG noted Mr. Liddle's suggestion that ATCO Pipelines should avoid discriminatory rates. AUMA/EDM/CG submitted ATCO Pipelines should make it known to all customers that if they could demonstrate their ability to take truly incremental summer gas with no additional facilities investment, they would be able to avail themselves of a contract similar to the TransGas non-standard contract. AUMA/EDM/CG recommended any such future contract should have a high standard of proof that the load was truly incremental.

Subject to the above conditions, AUMA/EDM/CG were prepared to recommend approval of the TransGas contract.

Calgary

Calgary generally accepted the recommendations of Mr. Liddle.

IGCAA

IGCAA submitted that all non-standard agreements should be approved for their entire term.

NGTL

NGTL submitted the purpose and nature of the TransGas non-standard contract appeared to be distinctly different from those of the other proposed non-standard contracts. NGTL stated that it was important the Board recognized the distinctions in determining the appropriate criteria to

[85] Tr. p. 996

judge the merits of the TransGas non-standard contract, and ultimately in deciding whether or not to approve it in this proceeding.

NGTL argued the TransGas non-standard agreement was not a defensive response to a perceived competitive and credible threat of bypass of the ATCO system, which was ostensibly the case with the other proposed non-standard contracts. NGTL submitted that ATCO Pipelines did not claim or provide evidence that TransGas had a competitive alternative to ATCO Pipelines' services and that TransGas would have accessed that alternative absent the special deal offered by ATCO Pipelines. NGTL argued ATCO Pipelines had, in its justification of the TransGas non-standard contract, completely ignored the first of the two "tests" that it advocated should be used to judge the merits of non-standard contracts. NGTL argued the only evidence ATCO Pipelines provided was a statement in cross-examination.[86]

NGTL stated that ATCO Pipelines apparently relied solely on the second of its two advocated tests to justify the TransGas non-standard contract, that there was a net benefit to other customers on the ATCO Pipelines system. NGTL suggested that a "net benefit test" could not by itself justify the TransGas or any non-standard contract. NGTL argued that in the absence of a viable service alternative, it was absurd to suggest that a customer's rate and service conditions could reasonably be established solely on whether the agreement provided a net benefit to the system.

NGTL argued that the perceived need for the TransGas non-standard contract appeared to be integrally tied to the existence and operation of ATCO Pipelines' exchange service and the EDA. NGTL suggested that any changes to the operation of the exchange service should impact the need for and the represented benefits of the TransGas non-standard contract. NGTL argued that the exchange service would be examined in detail in ATCO Pipelines' Phase II proceeding. Accordingly, NGTL suggested it might be premature for the Board to consider the prudence of the TransGas non-standard contract in this proceeding.

Views of the Board

The Board notes that customers generally accepted that the contract was beneficial to the ATCO Pipelines system. However, customers were concerned whether ATCO Pipelines had demonstrated that the TransGas contract was incremental. Customers were also concerned whether ATCO Pipelines was being discriminatory with respect to this service offering to TransGas.

The Board also notes that NGTL raised similar issues regarding the degree to which ATCO Pipelines satisfied its stated criteria for offering non-standard contracts, particularly, that the service was incremental. NGTL recommended that the approval be deferred until the upcoming Phase II where the exchange service would be examined in detail.

The Board considers that any new arrangements similar to the TransGas contract will be subject to approval by the Board prior to implementation. However, the Board believes it should address the TransGas contract in this Decision.

The Board notes that there were several attempts through information requests and cross-examination to clarify whether or not, and how the TransGas service was incremental. The Board

[86] Tr., p. 996

notes that ATCO Pipelines' submission that the service was incremental was not refuted by contrary evidence. The Board notes that either ATCO Pipelines or TransGas can terminate the contract on twelve months' notice.

Therefore, the Board is prepared to accept this contract for the 2003/2004 test years. The Board believes the issue of shifting loads from pipeline to pipeline (i.e. the load is not truly incremental to the province) should be addressed in either a future hearing on competitive pipeline issues, or ATCO Pipelines next GRA.

7.4.10 Calpine – Calgary Energy Centre Non-Standard Contract

Views of the Applicant

ATCO Pipelines submitted that it entered into a non-standard contract with Calpine for 55 TJ/day of firm delivery service to Calpine's proposed 250 MW Calgary Energy Centre power plant. ATCO Pipelines submitted that Calpine had three options for natural gas service, all in the immediate vicinity of its plant site: ATCO Pipelines, NGTL, and a large gas processing plant. ATCO Pipelines determined that Calpine's competitive option was to source 60% of its gas requirements from NGTL (with zero toll and no fuel on delivery) and 40% from the adjacent gas plant. ATCO Pipelines submitted that Calpine could acquire gas at a discount to AECO pricing due to the sharing of avoided receipt tolls for the gas plant direct connect volumes.

ATCO Pipelines forecasted annual savings to the EDA of $2,483,000 due to accessing the Calpine load. ATCO Pipelines submitted the capital cost for the facilities required to serve Calpine was $1,192,000. ATCO Pipelines argued that in order to compete for and connect the Calpine load to ATCO Pipelines' oversupplied south system and to achieve significant south EDA benefits, it was necessary for ATCO Pipelines to reduce the delivery toll and UFG/Fuel component as per the non-standard contract. The non-standard contract provided for a fixed charge of $1,000/month, a delivery toll of $0/GJ and a fixed UFG/Fuel rate of 0.25%.

ATCO Pipelines submitted the rate for service negotiated with Calpine provided a forecast savings to Calpine of $0.015/GJ at a NIT price of $2.00/GJ and $0.00/GJ at $11.00/GJ. ATCO Pipelines stated that the agreement had mutual termination rights upon twelve months' notice. ATCO Pipelines submitted that should Calpine terminate service, it would be responsible for the undepreciated capital cost of facilities installed to serve Calpine.

ATCO Pipelines suggested that Mr. Liddle took no issue with the benefits of the Calpine agreement to the EDA. ATCO Pipelines submitted that Mr. Liddle's recommended denial of the agreement in his original written evidence was significantly based on his view that only producer customers utilizing the exchange service benefited from the EDA, while all customers bore the resultant higher costs because of the lack of contribution other than the $12,000 per year. However, ATCO Pipelines submitted that its evidence, as agreed to by Mr. Liddle, was that the reduction in the EDA made ATCO Pipelines tolls more competitive and served to retain producer volumes. ATCO Pipelines submitted that Mr. Liddle stated under cross-examination that he did not take issue with the general proposition that anything ATCO Pipelines did to retain producer business created revenue that was a benefit to the ATCO Pipelines system.

ATCO Pipelines argued the Calpine non-standard contract was negotiated as a package and that each condition of the non-standard contract was a factor with value to one or both parties. Changing the conditions would impact the value for the parties. ATCO Pipelines submitted that

it successfully negotiated the first right to the Calpine load up to 55 TJ/day for the ten-year term of the agreement. ATCO Pipelines argued that renegotiation of the contract could result in the loss of this first right, which would significantly reduce the value of this contract to ATCO Pipelines' customers.

ATCO Pipelines argued that Calgary's comments regarding the Calpine contract should be given no weight by the Board as they mistakenly indicated that the contract did not recover the full UFG when in fact the contract currently contributed more UFG (0.25%) than other customers contributed via the current Rider "D" amount of 0.19%.

ATCO Pipelines therefore submitted that the non-standard contract was prudent and should be approved as filed for its term.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG submitted that the Calpine non-standard contract required incremental facilities but, other than a nominal charge of $12,000/year, made no direct contribution to the revenue requirements of ATCO Pipelines. AUMA/EDM/CG argued the non-standard contract was different from all other ATCO Pipelines non-standard contracts that required facilities, where either a DGP type mechanism or a negotiated rate was in place designed to either recover incremental costs or make a significant contribution to those costs. AUMA/EDM/CG submitted recovery of incremental costs should be a necessary component of any nonstandard contract involving incremental facilities.

AUMA/EDM/CG submitted that the EDA impact was only identified as an additional qualitative positive impact for the other non-standard contracts, whereas in the Calpine contract, the EDA benefit is quantified and is, in fact, the only substantive benefit of the contract.

While AUMA/EDM/CG agreed the contract made a positive contribution to the EDA, in its present form the EDA only benefited producer customers. Further, at any time Rider D is greater than 0.25%, the fixed contractual level of the UFG, there would be a further cost to customers.

Based on a combination of all these factors, Mr. Liddle recommend the Board not approve the Calpine contract. AUMA/EDM/CG agreed with Mr. Liddle's recommendation. AUMA/EDM/CG argued that until ATCO Pipelines renegotiated the contract, or Calpine entered a standard contract, revenue from the Calpine contract should be deemed at standard contract rates with the shortfall between the present rate of $12,000/year and the standard contract rate being made up by ATCO Pipelines' shareholders.

AUMA/EDM/CG argued that should the Board accept the recommendation of ATCO Pipelines to approve the contract on the basis of its positive contribution to the EDA being greater than its cost of service, then AUMA/EDM/CG recommended a charge be made against the EDA equivalent to the cost of service of the incremental facilities pursuant to the mechanism proposed by Mr. Liddle. Further, AUMA/EDM/CG argued that any approval term of the Calpine non-standard contract should be clearly limited to the term of existence for the EDA.

Calgary

Calgary generally accepted the recommendations of Mr. Liddle. Calgary concurred that the Calpine non-standard contract, as structured, should not be approved since it did not recover the full UFG, ensure recovery of the incremental revenue requirement created by the incremental facilities, or appear to provide for the recovery of incremental capital costs not recovered by the end of the contract.

IGCAA

IGCAA submitted that all non-standard agreements should be approved for their entire term. IGCAA argued there should be no issue with respect to this contract. IGCAA submitted that in Decision 2001-97 the Board approved a cost of service study that demonstrated that the receipt toll in the south covered the full cost of service to the industrial market. In effect, ATCO Pipelines' service to industrials in the south was no different than NGTL's rate design where the receipt toll, in and of itself, was sufficient to fully recover allocated transportation costs. IGCAA argued that, based on the Board's conclusions in Decision 2001-97, there was no basis for denying the Calpine non-standard contract.

Views of the Board

The Board notes ATCO Pipelines' argument that the Calpine non-standard contract was negotiated as a package and that each condition of the non-standard contract was a factor with value to one or both parties. The Board understands that ATCO Pipelines and Calpine might have approached the negotiation in that manner. However, the Board considers that other customers that might be impacted by various aspects of the 'package', through their rates on the ATCO Pipelines system, might not agree with that approach. Similarly, the Board does not consider itself precluded from adjusting individual aspects of the contract as deemed necessary. The Board respects ATCO Pipelines' prerogative to negotiate with prospective customers. However, when the contract is non-standard, the Board considers that it must be satisfied that other customers are not negatively impacted.

The Board notes that AUMA/EDM/CG and Calgary recommended that any shortfall between the fixed UFG and Fuel rate of 0.25% and Rider D should be subject to either a charge to the EDA or a deferral account. The Board notes that the fixed rate will vary from the actual Rider D over time, however, in this case is not convinced that the fixed rate of 0.25% is unreasonable over the term of the contract, given the overall potential benefit of the contract associated with the EDA.

The Board notes that AUMA/EDM/CG and Calgary also recommended alternatives whereby any revenue shortfall associated with the other components of the non-standard contract could be deferred or recovered from the EDA. The Board notes that there is no demand revenue collected to guarantee the recovery of incremental capital. However, the Board notes that the contract contains a facilities buyout on termination by Calpine.

The Board also notes that there is no direct contribution toward incremental O&M, or ATCO Pipelines' other mainline costs, except for the $12,000 per year fixed charge. However, all parties acknowledged that there was a positive impact on the EDA resulting from the attraction of Calpine to the ATCO Pipelines system, as long as the EDA is in existence substantially as constituted in December 2001.

The Board notes IGCAA's argument that the cost of service will be recovered through the receipt toll. However, the Board is not certain that any significant incremental receipts will be realized as a result of this contract. Rather, as previously stated, the Board believes that benefits would potentially be realized through the EDA.

In the Board's view, the contract appears to provide a benefit to the ATCO Pipelines system as long as the EDA and the exchange service, or a comparable service, is in existence substantially as constituted in December 2001. The Board notes that interveners had contradictory views regarding the appropriate manner by which the allocation of the costs and benefits of the Calpine contract should be addressed. The Board notes that AUMA/EDM/CG recommended that all costs associated with the contract should be charged to the EDA to ensure that core customers were not negatively impacted. Alternatively, the Board could address this matter in the upcoming Phase II.

The Board considers that it has four options: it could deny the contract, charge the costs to the EDA or another deferral account, approve the contract and address the allocation of any costs or benefits associated with it at the Phase II proceeding, or approve the contract subject to the existence of an EDA or similar exchange mechanism.

With respect to the first option, the Board believes that if it were to deny the contract, the net benefit to the EDA would not be realized for customers. Secondly, if the Board were to charge the costs to the EDA or another deferral account, the issue of dealing with unrecovered costs would simply be deferred. With respect to the third option, the Board finds that it is not satisfied enough with the security of the fundamental benefit to customers through the EDA to approve the contract. Therefore the Board will consider the fourth option, approving the contract subject to the existence of an EDA or similar exchange mechanism, which provides benefits to customers.

The Board is prepared to approve the Calpine non-standard contract since it provides a net benefit to the system. However the Board has a major concern that these benefits could be transitory, should the exchange mechanism be altered in the future to the extent that the net benefit would be lost.

The Board has additional concerns with the Calpine non-standard contract. In particular, these concerns relate to the timing of its filing for information with the Board, the relevant criteria for approval of non-standard contracts, and the shifting of risk to customers.

With respect to the timing of the filing of this contract with the Board in January, 2003, the Board notes that the contract commenced in December, 2001 and was revised in September, 2002. No explanation was provided by ATCO Pipelines as to why the contract was filed at such a late date after commencement. The effect of the late filing is that no scrutiny of the contract, and related costs and benefits, could be made in a timely way.

With regard to the applicable tests for approval of non-standard contracts in 2001, the Board has considered the information that would have been available to ATCO Pipelines at the time it entered the contract, and notes that ATCO Pipelines would not have met both of those tests at the time the contract was entered into. The tests were whether:

i.) A competitive alternative exists which would result in a loss of the customer without the non-standard agreement; and
ii.) The remaining customers realize a net benefit.

The Board considers that ATCO Pipelines could not have met the first test since Calpine was a new load, not a customer that could have been lost to a competitive alternative. Further, the Board has concerns that the second test is met only through the EDA mechanism, which will be subject to change over the fairly lengthy term of the contract (minimum term ending in 2012). The Board considers that a more reasonable approach would have been for ATCO Pipelines to have provided for contract re-openers relating to the demand charge in the case of material changes to the EDA mechanism which would substantially reduce or curtail the net benefit of the exchange volumes to the system in the South.

With respect to the shifting of risk, the Board believes that ATCO Pipelines entered into this contract at shareholder risk prior to Board approval. Once the Board approves the contract the risk shifts to customers. The Board considers in this case that, since so little of the cost of service is recovered from Calpine, the shift in risk to remaining customers is too great without ensuring that the single net benefit to remaining customers (EDA volumes) is secured. The Board considers that a re-opener of the contract in terms of the demand charge would have represented such a securing of benefit.

Since a re-opener to the demand charge does not exist in the contract, the Board will approve the contract for inclusion in ATCO Pipelines' cost of service only for such period that the EDA mechanism, or a like alternative, exists in substantially the form it did in December, 2001, or until the Minimum Term Date of 2012, so that the net benefits of additional delivery volumes in the South are realized.

The Board considers that the Calpine contract reflects competitive pipeline issues and demonstrates the need for a uniform pre-approval process for non-standard contracts applicable to all regulated pipelines in order to appropriately review the issues.

7.5 Industrial Revenue Forecasts

7.5.1 Firm Service Revenue Forecasts

Views of the Applicant

ATCO Pipelines submitted that the industrial sector contributed over 23% of APN's total revenue forecast in 2003 and 24% of the total revenue forecast in 2004. Industrial revenues were forecast to increase by 3.7% ($781,000) in 2003 over 2002. Industrial revenues were forecast to decrease by 4.0% ($868,000) in 2004 versus 2003.

The APN 2003 industrial delivery revenue increase was attributed to a forecasted increase in the rate for industrial commodity service to the Fort Saskatchewan based customers. The rate for industrial commodity service was based on ATCO Pipelines providing industrial customers with a competitive delivered gate price as compared to NGTL delivered plant gate cost. The rate was forecast to rise in 2003 due to a new NGTL intra-Alberta delivery toll, which ATCO Pipelines estimated to be 5¢/GJ, at the time of the Application, pending a Board decision. The 2004 industrial revenue decrease was attributable to the transition of industrial sales customers

including power plant customers and the University of Alberta to industrial firm service. ATCO Pipelines did not plan to offer a sales service after October 31, 2004.

The industrial sector contributed 3.2% of APS's total revenue forecast in 2003 and 3.7% of the total revenue forecast in 2004. Industrial firm service revenue was forecast to decrease by 20.6% ($278,000) in 2003 over 2002. The reduced revenues were the result of losing an industrial customer to an alternative fuel (coal). Revenue from this customer was forecast to be zero in both 2003 and 2004.

ATCO Pipelines submitted that historical trending and regular discussions with the industrial customers provided the most cost-effective and accurate means to determine the risk to the natural gas requirements of their plants. In times of high price or market volatility, contact with the customers occurred more frequently as throughput forecasts for the end-use markets could impact other aspects of ATCO Pipelines' business. Industrial plant shutdowns could be temporary or permanent in nature and could occur as a result of high natural gas prices and/or instability in the markets of the produced commodity. ATCO Pipelines submitted that very little information existed in the public domain relating to the actual impact on a specific plant's viability due to commodity or energy pricing.

The Application did not specifically identify industrial revenues as being subject to NGTL placeholders. ATCO Pipelines argued that since the delivered gate price (DGP) used by ATCO Pipelines in several non-standard contracts included the NGTL FT-A toll, the compliance filing would also adjust the DGP rate from the assumed FT-A ($.05/GJ) to the actual FT-A. ATCO Pipelines submitted that Decision 2003-051 issued subsequent to the Application approved the NGTL proposed $.016/mcf FT-A toll for 2003 and ordered NGTL to file a 2004 Phase II Application.

ATCO Pipelines submitted in BR.AP-32 that it was cognizant that NGTL would likely be implementing intra-Alberta charges in their upcoming tariff application. The specific types of intra-Alberta charges, and the tolling for, were not known when ATCO Pipelines compiled the Application. Given that these charges would be subject to Board approval in NGTL's Tariff Application, as well as the overall magnitude of the charges relative to ATCO Pipelines' revenue requirement, ATCO Pipelines determined that these charges should be a placeholder in this Application. As with the other placeholders (Section 1.1, lines 1-13), the final resolution of each was proposed through the compliance filing, based on Board directions.

ATCO Pipelines submitted that the NGTL placeholder included the impact of the variance of the approved NGTL charges from the assumed charges in the Application on the DGP, and ultimately on the industrial revenue forecast pursuant to the compliance filing.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG noted that in aggregate, the ATCO Pipelines forecast of industrial firm revenue was essentially flat for 2003 and 2004 compared to 2002. AUMA/EDM/CG submitted that it seemed reasonable given the relatively high price for the gas commodity and the downward pressure that high prices created in the industrial market.

AUMA/EDM/CG also noted that with the issuance of Decision 2003-051, the NGTL intra-Alberta delivery charges were known for 2003. AUMA/EDM/CG suggested those known charges could be used in calculating the forecast revenue to be received under the non-standard contracts that utilized a DGP mechanism for determining the contract price.

Views of the Board

The Board notes that the AUMA/EDM/CG suggested the industrial firm revenue forecast seemed to be reasonable, and that it could be adjusted to reflect the impact on the DGP related to Decision 2003-051. The Board agrees that ATCO Pipelines' forecast is reasonable.

The Board notes that the magnitude of the impact of the compliance filing on the industrial firm revenue forecast is not clear. The Board considers that the Application was not clear with respect to any impact the NGTL placeholder would have on the industrial firm revenue forecast. Furthermore, the Board notes that ATCO Pipelines only referred specifically to the impact on the DGP in an information response, and subsequently in the O&M section of ATCO Pipelines' argument.

The Board does not object to adjusting ATCO Pipelines' revenue forecast to reflect Decision 2003-051, even though the Board is not certain that ATCO Pipelines originally intended to adjust industrial firm revenue pursuant to the NGTL placeholder. The Board is aware of ATCO Pipelines' views regarding the preservation of the prospective test year, and considered excluding this amount from the NGTL placeholder. However, the Board considers that it is reasonable to adjust the industrial firm revenue forecast to incorporate the impact on the DGP pursuant to Decision 2003-051.

7.5.2 Interruptible and Overrun Revenue Forecasts

Views of the Applicant

ATCO Pipelines submitted that industrial interruptible/overrun revenues were forecast to be zero in both 2003 and 2004 due to the unpredictability of 2002 trends.

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG submitted that ATCO Pipelines forecast of zero for both 2003 and 2004 for interruptible/overrun revenue was not reasonable. AUMA/EDM/CG noted the actual revenues for 2001 and 2002 were $125,000 and $108,000 respectively, and argued that a forecast of $100,000 of overrun revenue for both 2003 and 2004 would be more reasonable.

Views of the Board

The Board accepts that interruptible/overrun revenues can be difficult to forecast with certainty due to their nature; however, the Board does not agree that a forecast of zero is appropriate when the amount has approximated $100,000 for each year since 1999. Therefore, the Board considers that a forecast of $100,000 for both 2003 and 2004, allocated 75% to APN and 25% to APS is appropriate and directs ATCO Pipelines, in its Refiling, to include this amount in its interruptible revenue forecast.

7.6 ATCO Gas/Core Market Revenue Forecasts

7.6.1 Contract with ATCO Gas

Views of the Applicant

ATCO Pipelines submitted that the contract with ATCO Gas was renegotiated. ATCO Pipelines requested approval for the full term of the contract. ATCO Pipelines also sought approval to "reflect the progression of the organizational transition and to ensure the appropriate responsibility and accountability for new facilities".

ATCO Pipelines argued that the old agreement had a mismatch between the billing basis (24-hour peak demand), the 4-hour peak design used by ATCO Pipelines, and the 1-hour peak design basis used by ATCO Gas. ATCO Pipelines submitted that ATCO Gas selected a one-hour design basis. ATCO Pipelines argued that billing should match design. ATCO Pipelines submitted that changes to the contract would not impact capital or operating expenditures or the total revenue requirement.

The present 24-hour peak demand used to determine the ATCO Pipelines revenue forecast was selected prior to, and made available prior to, the ATCO Gas GRA.

ATCO Pipelines submitted that:[87]

> The most significant issue was the mismatch of the design basis peak (Clause 5.1) which ATCO Pipelines was obligated to build to versus the billing basis (Clause 9.2) which was calculated on a different basis, namely the Phase 2 peak. ATCO Gas' design basis peak was increasing, ATCO Pipelines was installing facilities to meet the ATCO Gas increased design peaks but at the same time the billing peak was decreasing, resulting in lower revenues.
>
> The other issue resolved through these amendments is to align the design basis with ATCO Gas' need – the design basis (1 hour) that ATCO Gas uses for its own facilities. This now obligates ATCO Pipelines to meet the one hour requirement while optimizing the design for the ATCO Pipelines system (a four hour peak which utilizes a swing in line pack to meet the one hour peak). Exceptions to the ATCO Pipelines four hour peak design period include smaller gas transmission pipelines delivering gas to ATCO Gas and other Distribution Companies, these pipelines have insufficient line pack and therefore must be designed for a one hour peak.
>
> It was agreed that the design peak basis reflected capital cost causation and was the most appropriate billing basis on a go-forward basis (effective January 1, 2003).
>
> The one hour peak design quantity reflects the peak hydraulic capacity requirement that ATCO Pipelines' transmission system must operationally accommodate. ATCO Pipelines needs to use the data that most precisely reflects the customers' transportation requirements to ensure the pipeline system operation is optimized and a secure supply is provided.

87 BR.AP-42

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG submitted that principle issue related to the shift by ATCO Gas to a one-hour peak demand design basis, for both design and billing demand. AUMA/EDM/CG noted ATCO Pipelines' submission that there would not be an impact on facilities required by ATCO Pipelines to serve ATCO Gas load, and that the total revenue requirement would not change. AUMA/EDM/CG also noted that the impact of the change to the contract would be an issue for Phase II.

Calgary

Calgary submitted the contract was not a 'real' contract, as it was between divisions of the same corporation. Calgary questioned why approval of the contract was required to 'reflect the progression of organization transition'. Calgary argued that ATCO continued to make organizational changes.

Calgary submitted that ATCO Gas and ATCO Pipelines were responsible to and accountable for new facilities. Calgary argued there was no need for approval of the contract as was suggested by ATCO Pipelines on that basis.

Calgary argued the contract was not disclosed in the ATCO Gas 2003/04 GRA, and that underlying data was not provided to support the change to a 1-hour peak.

Views of the Board

The Board is not convinced that it is necessary to approve any part of the contract in this Decision. The Board notes that while the change to 1-hour peak day design purposes appears to be reasonable, there is no need for the Board to approve the change in Phase I. Similarly, the Board is not convinced that it is required to approve other aspects of the contract in this Decision (i.e. those related to the change to the peak used for billing purposes, the contract term, or the exclusivity provisions, etc.)

The Board appreciates that ATCO Pipelines and ATCO Gas might be attempting to 'tighten' up their arrangement, however, the Board is not convinced that approval of those issues is required in this Decision.

The Board will address relevant changes to the contract, as necessary, in the Phase II proceeding.

7.6.2 Billing Determinants and Revenue Forecast for ATCO Gas/Core Market

Views of the Applicant

ATCO Pipelines submitted that for ATCO Gas North, the 2002 demand rate of $2.10/GJ/month was used in 2003/04 and applied to the 24-hour peak day of 1122 TJ/day for 2003 and 1132 TJ/day for 2004. ATCO submitted the demand amounts were the theoretical 24-hour peak used for Phase II cost allocation purposes.

ATCO Pipelines argued that the $10.32 million credit booked in 2001 & 2002 was related to the North Core Settlement and should not be applied to the demand rate for 2003/04 as was submitted by AUMA/EDM/CG.

ATCO Pipelines submitted that for ATCO Gas South, the 2001/02 demand rate as per the GRA of $1.605/GJ/month was used in 2003/04 and applied to the 24-hour peak day of 1014 TJ/day for 2003 and 2004. ATCO Pipelines submitted the demand amounts were the theoretical 24-hour peak used for Phase II cost allocation purposes.

ATCO Pipelines submitted that ATCO Gas previously provided peak demand amounts (12 months in advance of effective calendar year). ATCO Pipelines argued that customers had ample notice and opportunity to pursue billing determinants with ATCO Gas at the ATCO Gas 2003/2004 GRA.

ATCO Pipelines submitted that the 1-hour peak was approximately:

- 10% greater than 24-hour peak
- the 1-hour peak is approximately 2% greater than 4-hour peak
- the 4-hour peak is approximately 8% greater than 24-hour peak

ATCO Pipelines submitted that the 24-hour peak day for ATCO Gas North and South has been relatively constant since 1999. In addition, the ATCO Pipelines provided information whereby the following comparisons could be made regarding the difference between the 24-hour peak used to forecast revenue and the 1-hour peak design submitted in the Application (pages 4 and 13 of section 5.1)

Table 33. Peak Demand Forecast 1-hour vs. 24-hour

	(1-hour x 24 hours) peak	24-hour peak	Difference (%)
North 2003 – 51231 GJ/hour	1229.5 TJ/d	1122	9.6%
North 2004 – 52458 GJ/hour	1259.0 TJ/d	1132	11.1%
South 2003 – 45568 GJ/hour	1093.6 TJ/d	1014	8.15%
South 2004 – 46654 GJ/hour	1119.7 TJ/d	1024	9.35%

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG submitted that its primary concern in APN related to the $2.10 demand rate, in light of the 14% reduction ($10,320,000 adjustment) that was allocated between AGN & APN pursuant to the North Core Re-opener.

AUMA/EDM/CG argued that, at a minimum, the demand rate with respect to ATCO Gas North should be reduced by 14%, to $1.806, or alternatively by a maximum reduction of 35.8% to $1.348.

FGA

FGA submitted that ATCO Gas represents 93% of revenue in the distribution companies' revenue forecast. FGA noted that when ATCO Pipelines forecasts its billing determinants for the ATCO Gas portion of revenue, ATCO Gas determined the design peak of each of its delivery

points and provided them to ATCO Pipelines [88]. FGA argued that was appropriate as the distribution company would have the best information available for its business. FGA suggested that a local distribution company (LDC) should best know its own forecast for growth and the design factors required of its own systems.

Views of the Board

The Board notes that the ATCO Pipelines revenue forecast was based on the 24-hour peak demand, rather than the 1-hour peak demand amounts provided in the Application. The Board notes that the 24-hour peak demand was relatively flat compared to prior years, and that interveners did not address that amount in Argument. The Board also notes the FGA's submission that it is appropriate for ATCO Pipelines to obtain a forecast from the distribution company regarding its forecast for growth and the design factor for the stations on its system. Therefore, the Board approves the 24-hour peak demand amounts used to calculate the revenue from ATCO Gas North and South.

The Board also notes that different amounts were used with respect to the demand rate. The Board approves the use of the $1.605 rate used for ATCO Gas South. The Board notes the AUMA/EDM/CG argument regarding the demand rate with respect to ATCO Gas North. The Board is convinced that it is appropriate to reduce the demand rate used to forecast ATCO Gas North revenue by 14%, to $1.806.

The Board will address the change to a 1-hour peak day design (for billing purposes) as part of the Phase II proceeding.

7.7 Gas Co-ops, FGA and Other Distributing Customers' Revenue Forecasts

Views of the Applicant

ATCO Pipelines submitted that the Gas Alberta revenue forecast in the North was based on contract demand of 48 TJ/d using the same demand rate as for ATCO Gas North $2.10. ATCO Pipelines submitted that the Gas Alberta revenue forecast in the South was based on contract demand of 11 TJ/d using the same demand rate as for ATCO Gas South 2001/2002 GRA of $1.95.

ATCO Pipelines submitted that the Gas Alberta demand forecast was based on a 27% peak day load factor (applied to throughput forecasts for 2003/04 based on 3 year average of monthly deliveries). ATCO Pipelines also submitted that the demand forecasts for Other Distributors were forecast to increase by 6% in 2003 and 2% in 2004

ATCO Pipelines agreed to work with Gas Alberta and other distributors in the future, but otherwise stood by the forecast. ATCO Pipelines noted there were changes to Gas Alberta regarding the transition from Rates 5 and 7 to transportation rates.

[88] Application, S. 5.1, p. 3 of 18, ll. 23-25

Views of the Interveners

AUMA/EDM/CG

AUMA/EDM/CG submitted they had not canvassed this issue in detail and would defer to the recommendations of other interveners, particularly FGA, who are clearly in a better position to advise the Board with respect to the reasonableness of the forecast for their own service areas.

With respect to other distributing companies, AUMA/EDM/CG noted there was little change in the forecast for 2003 and 2004 compared to 2002 actuals. Therefore, AUMA/EDM/CG submitted they were prepared to accept the forecast as reasonable.

FGA

FGA submitted that the ATCO Pipelines revenue forecasts for the Other Distributing Companies (Gas Alberta and Rate 5 customers) representing the remaining 7% of Distributing Company revenue was not of the same quality as for the ATCO Gas component. FGA argued that in the case of these smaller customers, it appeared as if ATCO Pipelines had relied on its own data and thereby forecast these revenues based on a three year average of past demand.[89] FGA argued that all LDCs served by ATCO Pipelines merited the same treatment as afforded ATCO Gas.

FGA noted that there was the matter of materiality to take into consideration. FGA noted that the Other Distributing Companies made up a much smaller portion of ATCO Pipelines' volumes than ATCO Gas did. FGA submitted it accepted the ATCO Pipelines commitment to work with its smaller customers to ensure that the best revenue forecasts are incorporated in its filings.[90] FGA stated that it hoped that the ATCO Pipelines consultation with FGA and other distributing customers would provide superior quality of information and results for 2003 and future test years.

However, FGA stated they did not agree with the forecast billing determinants by which the revenue forecasts were derived, as these were not derived from the business plans of these other utilities. In addition to the billing determinants, Rates 5 and Rate 7 were in transition from sales rates to transportation rates[91]. These rates were not suitable for transportation service and had been interim since January 1, 2003. The rates that were ultimately set for Rates 5 and 7 would be quite different from the current rates, further changing the revenue forecast for the Other Distributing Companies.

FGA argued that although the current Rates 5 and 7 were interim and adjustable, any adjustments required to keep Rate 5 and Rate 7 customers whole should be kept to a minimum. Therefore, it was a matter of some urgency that the Board proceed with a 2003 Phase II rate hearing. FGA submitted that ATCO Pipelines must proceed with its proposed September filing of rates, including an application for new interim transportation rates for the Other Distributing Companies.

Given the concerns expressed, FGA requested that the Board not approve ATCO Pipelines' revenue forecast for 2003/2004. FGA submitted that the Board should consider revenues a

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89 Tr. p. 334, lines 18-21, Tr. p. 339, lines 15-18 & Tr. p. 377, lines 19-21
90 Tr. p. 341, lines 11-17
91 Tr. p. 336, lines 16-22

placeholder to be determined in the Phase II hearing, preferably after consultation between customers and ATCO Pipelines.

Views of the Board

The Board notes the issues raised by the FGA with respect to the manner by which the forecast of Gas Alberta and Other Distributors was determined by ATCO Pipelines. The Board agrees that ATCO Pipelines should work more closely with Gas Alberta and Other Distributors when the forecast demand is developed. However, the Board is not convinced that it is necessary or reasonable to consider these revenues as a placeholder to be determined in the Phase II hearing as suggested by the FGA.

While Gas Alberta is forecast to undergo rate changes in the test period, the Board considers this to be a Phase II issue. The Board will address FGA's relevant concerns in Phase II of this proceeding.

7.8 Other Revenue

Views of the Applicant

ATCO Pipelines submitted that other revenue was approximately 1.7% of the ATCO Pipelines total revenue in 2003 ($1,612,000) and 1.5% in 2004 ($1,322,000). Other revenue was comprised of pipeline leases, gas processing services, Alliance delivery service, and affiliate revenue (ATCO Midstream). ATCO Pipelines submitted that other revenue was constant for all sources during the two test years, except for declines in pipeline leases due to contract terminations.

Views of the Interveners

Interveners asked a few information requests related to other revenues, however, they did not address other revenue in argument.

Views of the Board

The Board considers that the other revenue forecast is reasonable and is therefore approved as filed.

8 SUMMARY OF BOARD DIRECTIONS

This section is provided for the convenience of readers. In the event of any difference between the Directions in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

1. Accordingly, the Board directs ATCO Pipelines, in a refiling to their Decision (the Refiling), to set its 2003 opening balances for Property Plant and Equipment, Accumulated Depreciation, and Net Contributions for ATCO Pipelines Total, APN, and APS equal to the 2002 closing balances..4
2. Based on the foregoing, the Board directs ATCO Pipelines, in its Refiling, to file the revenue requirement separately for North and South. The Board therefore expects that the outcome of this Phase I process will be the setting of separate revenue requirements for North and South,

11. The Board supports the AUMA/EDM/CG submission that it would be beneficial to have information concerning the number of personal computers and servers being upgraded and the cost per unit. Information concerning software implementation and training costs would also be of assistance in reviewing projects of this nature. Therefore, the Board directs ATCO Pipelines, in future GRA's, to include this level of this detail in its business cases for IT projects of this nature. 37
12. However, the Board agrees with the submissions of interveners that ATCO Pipelines failed to adequately justify the costs of the TIS project via a business case or cost benefit analysis. ATCO Pipelines' statement in cross-examination that benefits of the project are " blatantly obvious", does not justify the appropriateness of the project. However, the Board recognizes that Centura is an outdated programming language that requires an upgrade to hardware and software tools, and Centura programmers may be difficult to find. Therefore, the Board considers that while ATCO Pipelines failed to fully justify the costs of the project, it did show a need for the project. Therefore, the Board will allow the TIS project, but based on the Applicant's failure to adequately justify the costs of the project, the allowed expenditures shall be reduced by 15%. 38
13. The Board also considers, and directs, that for all future IT application or technology projects over $500,000, ATCO Pipelines should provide, within the IT project business cases, the impact on I-Tek volumes in the same manner as contracted from its I-Tek affiliate (e.g. mainframe services, distributed services, network services, workstation services, and application services). 38
14. The Board considers that the forecast amounts for Transmission Replacement-General for APN are reasonable. In the future, the Board expects ATCO Pipelines to alleviate the concerns of interveners regarding double counting by providing greater clarity in expenditure descriptions and breakdowns of costs in the original application. The Board accepts the forecasts as filed. 39
15. The Board directs ATCO Pipelines, in the Refiling, to reduce its forecast of Replacement General South by 15% in each test year. 42
16. The Board therefore considers the forecast expenditures for land and structures for both APS and APN is reasonable. However, the Board notes that it applied an adjustment to ATCO Pipelines forecast of Full Time Equivalents (FTEs) in the Operation and Maintenance section of this Decision. Therefore, the Board directs ATCO Pipelines to reflect the impact of the aforementioned adjustment on any affected land and structures expenditures in its compliance filing, including any supporting rationale in this category. 46
17. The Board notes the concerns of AUMA/EDM/CG that, for both APS and APN, moveable equipment expenditures should be replaced at uniform rate. However, the Board agrees with ATCO Pipelines' submission that the correct methodology is to replace vehicles as they end their useful life. The Board is of view that AUMA/EDM/CG's argument that moveable equipment expenditures for APN should remain the same as under the four year settlement, fails to take into consideration the give and take in the negotiated settlement process, and the useful life of the asset. Therefore, the Board accepts as reasonable ATCO's forecasts for 2003 and 2004 as filed. However, the Board notes that it applied an adjustment to ATCO Pipelines forecast of Full Time Equivalents (FTEs) in the Operation and Maintenance section of this decision. Therefore, the Board directs ATCO Pipelines to reflect the impact of the aforementioned adjustment on the moveable equipment expenditures in its compliance filing, including any supporting rationale in this category. 48

18. The Board agrees with ATCO that revising the O&M expense lag to reflect the payroll and payroll related expense lag calculation to include incentives does not materially affect the O&M expense lag. However, the Board believes that a revision to the payroll and payroll related expense lag provides a more accurate account of the lead lag study, and in the Board's view causes no administrative burden to ATCO. Therefore, the Board directs ATCO to revise the Payroll and Payroll related lag days to 13.89 days as indicated in Exhibit 29-18, and revise the O&M expense lag to reflect this change. 56

19. The Board agrees with Calgary's submission that since ATCO Pipelines and ATCO Gas are part of the same corporation, there should be no cash lag between the two divisions for working capital purposes. Accordingly, the Board directs ATCO to recalculate its lead/lag study with the application of a zero lag to transactions with ATCO Gas. 56

20. The Board notes the different treatment between payments to affiliates and other payments in the lead/lag study. Specifically, ATCO's proposed expense lag for affiliate payments (excluding I-Tek) is 20.96 days, as opposed to 35.50 days for other O&M expenses. The Board also notes that the expense lag for payments for I-Tek services is 53.21 days. The Board considers that, for the purposes of calculating the NWC requirement, there is no reason why the lag days for payments to affiliates should be any less than the lag relating to payments for arms length transactions. Accordingly, the Board directs ATCO to recalculate the NWC balance using an expense lag of 35.50 days for payments for affiliate services (excluding I-Tek). 56

21. With regards to I-Tek, the Board notes that ATCO Pipelines argued that should the Board direct it to revise the lag days for affiliates to be identical to O&M expenses, then the lag days for I-Tek should also be adjusted to 35.50 days from the contractually agreed lag of 53.21. The Board notes that AUMA/EDM/CG argued that this was a negotiated lag and presumably reflected the cost elements included in the pricing of I-Tek services, and the appropriateness of the costs associated with this expense lag would best be reviewed as part of the benchmarking process for I-Tek services. The Board believes that to remain consistent and fair in the treatment of affiliate transactions as it relates to the lead-lag study and NWC, I-Tek should be treated no differently than any other affiliate service. Therefore, the Board directs ATCO to revise its I-Tek Services lag to 35.50 days, consistent with other affiliate and non-affiliate transactions. 56

22. On the issue of Line Pack, the Board notes ATCO Pipelines' acknowledgment that customers had supplied the line pack over the years from unaccounted for gas. The Board agrees with the submission of Calgary that ATCO has failed to illustrate the benefits of the inclusion of Line Pack in NWC to customers. The Board considers that the inclusion of Line Pack inflates rate base and related costs to customers on an asset that was supplied by customers over the years from unaccounted for gas. The Board agrees with Calgary that there is no economic benefit to ratepayers in ATCO Pipelines owning the Line Pack. Therefore, the Board denies the acquisition of Line Pack to be added to inventory in NWC. The Board directs ATCO Pipelines, in its Refiling, to remove the amounts from the mid-year NWC provided in the test years for the proposed acquisition of Line Pack. 57

23. Therefore the Board approves the proportion of debt and preferred shares of APN and APS as set out by ATCO Pipelines in the Application, adjusted as necessary by the Board's determination of the deemed common equity ratio 58

24. The Board notes a significant divergence in the Application between the mid-year capitalization and mid-year Rate Base. The Board directs ATCO Pipelines, at the next GRA, to address this issue. 58
25. The Board directs ATCO Pipelines, in its Refiling, to use, for 2003, a return on common equity of 9.5% for purposes of calculating the revenue requirement. The ROE for 2004 will be a placeholder amount pending the outcome of the Generic Cost of Capital decision........ 72
26. The Board therefore directs ATCO Pipelines to use the same deemed common equity ratio for APN and APS. 73
27. Therefore, the Board directs ATCO Pipelines to reflect a common equity ratio of 43.5% for both APN and APS in its Refiling for 2003 and to use 43.5% as a placeholder figure for 2004, pending a determination for that year in the Generic Cost of Capital proceeding........ 84
28. Accordingly, the Board directs ATCO Pipelines, in its Refiling, to recalculate transmission labour and supplies expenses for both 2003 and 2004 using an inflation rate of 3.15%. 87
29. The Board also directs ATCO Pipelines to file, in future GRA applications, more detailed information supporting its inflation factors........ 87
30. The Board directs ATCO Pipelines, in the next GRA, to identify its forecast of vacancies in FTEs including annualization of new FTEs. 90
31. The Boar directs ATCO Pipelines, in its Refiling, to recalculate the costs associated with an increase in FTEs of five for 2003 and two for 2004, and to show the corresponding reduction in costs from the original filing of 14 FTEs in 2003 and three FTEs in 2004. 91
32. Accordingly, the Board directs ATCO Pipelines to recalculate, in its Refiling of evidence, A&G labour and supplies expenses for both 2003 and 2004 using an inflation rate of 3.15% and to provide details showing the reduced costs. 92
33. Accordingly, the Board directs ATCO Pipelines in future GRAs, to provide details of all retirements from regulated operations since the preceding GRA, specifying years worked in regulated and non regulated divisions, the related chronology and the total number of years of employment used for pension purposes. Furthermore, for the purposes of completion of the record, ATCO Pipelines is directed, in its Refiling, to complete the Deferred Pension Continuity schedule, shown above, to include amounts for the years 2000 to 2004 inclusive. 94
34. The Board directs ATCO Pipelines to re-examine the treatment of the Deferred Pension balance in the next GRA and provide a detailed explanation and rationale for treatment of the gain in the Pension Deferral Account. 95
35. Accordingly, the Board directs ATCO Pipelines to reduce the assessment to the Hearing Cost Reserve account for 2003 to zero, allowing the closing balance for 2003 to be adjusted to $799,000, and adding $750,000 to the assessment for 2004. The Board also directs ATCO Pipelines to recalculate its 2003 and 2004 midyear Necessary Working Capital in accordance with this change. 96
36. The Board is of the view that it is reasonable to allow the reserve to accumulate enough funds to cover one major claim, or $1,000,000 every five years. If there is more than one major claim in a five-year period, the reserve fund could experience a deficit. However, the Board is not satisfied that there is a pressing need to bring the reserve to that level within the

44. The Board notes the concerns of AUMA/EDM/CG that the description of ATCO Pipelines' policies regarding these tax deductions is not sufficiently detailed. The Board has reviewed the response of ATCO Pipelines to AUMA/EDM.AP-29 and agrees with AUMA/EDM/CG that the noted policy statement is lacking sufficient detail. The Board directs ATCO Pipelines, at the next GRA, to file a written policy regarding the detailed use of the indirect overhead deduction and to provide a detailed variance analysis between actual and forecast deductions. 109
45. The Board is also of the view that provincial tax changes have been announced with an adequate degree of certainty to require a change to forecast income tax expense. 111
46. The Board notes that the rates of Provincial income tax proposed in the 2003 Provincial Budget were 12.5% (2003) and 11.5% (2004), whereas ATCO used the existing rate of 13% in calculating income tax expense. The Board considers that, although the amended rates have not yet been enacted, inclusion in the Provincial Budget gives the certainty envisaged in the CICA Handbook for application to corporations. 111
47. Therefore, the Board directs ATCO Pipelines, in its Refiling, as a placeholder, to use the rates that have been announced by the governments notwithstanding that the announced rates have not yet been enacted. Accordingly, recognizing that the rates are to be effective as of April 1, 2003, the Board directs ATCO to recalculate income tax expense to reflect the revised Provincial Income Tax rates of 12.62% (2003) and 11.75% (2004) on an annualized basis. 111
48. In addition to using the announced rates, the Board considers that an appropriately constructed deferral account would be fair for both customers and the company to capture any changes in Federal and Provincial tax rates over the test period. Accordingly, the Board directs ATCO to propose a deferral account in its Refiling that would account for any change in Federal resource allowances and tax rates and Alberta tax rates. 111
49. Therefore, the Board directs that ATCO Pipelines to file any future non-standard contracts with the Board prior to implementation, allowing sufficient time for interveners and the Board to conduct an appropriate review. The Board considers that this requirement applies to all utilities that it regulates. 135
50. The Board accepts that interruptible/overrun revenues can be difficult to forecast with certainty due to their nature; however, the Board does not agree that a forecast of zero is appropriate when the amount has approximated $100,000 for each year since 1999. Therefore, the Board considers that a forecast of $100,000 for both 2003 and 2004, allocated 75% to APN and 25% to APS is appropriate and directs ATCO Pipelines, in its Refiling, to include this amount in its interruptible revenue forecast. 156

9 ORDER

IT IS HEREBY ORDERED THAT:

(1) ATCO Pipelines shall comply with all Board directions in this Decision.

(2) ATCO Pipelines shall refile its 2003/2004 GRA (the Refiling), on or before January 26, 2004, incorporating the findings of the Board in this Decision.

(3) In the Refiling, ATCO Pipelines shall include all of the supporting schedules necessary for the Board to make its final determination respecting ATCO Pipelines' 2003/2004 revenue requirement. The Refiling shall be at a level of detail sufficient to reconcile with the original filing, and to demonstrate compliance with the Board's findings.

(4) With respect to certain matters in this proceeding, including ATCO I-Tek service fees to be benchmarked, ATCO executive compensation amounts, the Muskeg River pipeline module, 2004 Cost of Capital, actual income tax rates and actual NGTL charges, ATCO Pipelines shall include in the revenue requirement for the test years, the related expenditures and revenues as filed in the Application as "placeholder" amounts, pending final determination of these amounts in separate Board proceedings or otherwise by applicable authorities. ATCO will be required to adjust these "placeholder" amounts in the revenue requirement for the test years, after the Board has issued decisions on these separate matters, or after they have otherwise been finally determined by applicable authorities.

(5) ATCO Pipelines shall specifically identify in the Refiling, those items included in the revenue requirement as placeholders for the test years, and their related amounts.

Dated in Calgary, Alberta on December 2, 2003.

ALBERTA ENERGY AND UTILITIES BOARD

C. Dahl Rees
Presiding Member

B. T. McManus, Q.C.
Member

M. W. Edwards
Acting Member

APPENDIX 1 – HEARING PARTICIPANTS

Principals and Representatives (Abbreviations used in Report)	Witnesses
ATCO Pipelines N. Gretener M. Buchinski	R. Cerkiewicz W. Wright D. Belsheim B. McRae G. Lidgett K. McShane
Alberta Irrigation Projects Association H. Unryn	
Alberta Urban Municipalities Association (AUMA), the City of Edmonton, and Consumer's Group J. Bryan	B. Shymanski R. T. Liddle
BP Canada Energy Company C. Worthy	
Canadian Association of Petroleum Producers L. Manning	Dr. J. Chua G. Stringham R. Moore
Consumers Coalition of Alberta (CCA) J. A. Wachowich	
Federation of Alberta Gas Co-ops/Gas Alberta Inc. T. Marriott D. Jenkins	
Imperial Oil Resources R. Moore	
Industrial Gas Consumers Association of Alberta B. Roth	N. MacMurchy
Mirant Canada Energy Marketing Ltd. M. Stauft	
NOVA Gas Transmission Ltd. P. Keys	
Petro-Canada and Petro-Canada Oil and Gas S. Miller	

Principals and Representatives (Abbreviations used in Report)	Witnesses
Promark, Canadian Forest Products	
J. Gerwing	
Public Institutional Consumers of Alberta (PICA)	
N. McKenzie	
Talisman Energy Inc.	
F. Basham	
The Alberta Chicken Producers	
T. Weiss	
The City of Calgary (Calgary)	K. Sharp
R. Brander	H. Johnson
P. Quinton-Campbell	H. VanderVeen
R. Wood	J. Stephens
	L. Kennedy
	J. McCormick
	Dr. L. Booth
	Dr. M. Berkowitz
Treaty 8 First Nation and Aboriginal Communities	
J. Graves	
Alberta Energy and Utilities Board	
Board Panel	
C. Dahl Rees, Chair	
B. T. McManus, Member	
M. W. Edwards, Member	
Board Staff	
J. Hocking, Board Counsel	
A. Domes, Board Counsel	
D. Gray	
W. Vienneau	
M. McJannet	
S. Allen	
R. Nota	

APPENDIX 2 – ABBREVIATIONS

A&G means Administration and General
AGN means ATCO Gas North
AGA means American Gas Association
AIPA means Alberta Irrigation Projects Association
APN means ATCO Pipelines North
APS means ATCO Pipelines South
AUMA/EDM/CG means Alberta Urban Municipalities Association, City of Edmonton, and the Consumers Group
BCUC means British Columbia Utilities Commission
Board or EUB means the Alberta Energy and Utilities Board
CAPP means Canadian Association of Petroleum Producers
CAPM means Capital Asset Pricing Model
CCA means Capital Cost Allowance
CD means Contract Demand
CICA means Canadian Institute of Chartered Accountants
CPI means Consumer Price Index
CUL means Canadian Utilities Limited
CWNG means Canadian Western Natural Gas Company Limited
DBRS means Dominion Bond Rating Service
DCF means Discounted Cash Flow
DGP means Delivered Gate Price
EDA means Exchange Deferred Account
EGD means Enbridge Gas Distribution
ERP means Equity Risk Premium
FGA means the Federation of Gas Co-ops and Gas Alberta Inc.
FTEs means Full Time Equivalents
FSR means Firm Service Receipt
GDP means Gross Domestic Product
GJ means Gigajoule
GMS means Gas Management System
GRA means General Rate Application
IGCAA means Industrial Gas Consumers Association of Alberta
IT means Information Technology
LDC means Local Distribution Company
LRS means Load Retention Service
MAV means Minimum Annual Volume
NEB means Nation Energy Board
NGTL means NOVA Gas Transmission Ltd.
NOP means Normal Operating Pressure
NUL means Northwestern Utilities Limited
NWC means Necessary Working Capital
O&M means Operating and Maintenance
PHFFU means Plant Held for Future Use (account)
PICA means Public Institutional Consumers of Alberta
PNG means Pacific Northern Gas
ROE means Return on Equity
RID means Reserve for Injuries and Damages

S&P means Standard and Poor's
SCADA means Supervisory Control and Data Acquisition
scf means Square Cubic Feet
TCPL means TransCanada Pipelines
TIS means Transportation Information System
TJ means Tera Joules
UCC means Undepreciated Capital Cost
UFG means Unaccounted for Gas

APPENDIX 3 – BOARD DECISIONS/ORDERS REFERENCED

Decision E89091	TransAlta Utilities Corporation In the matter of a Filing by TransAlta Utilities Corporation, pursuant to a direction of the Public Utilities Board in Order C88027 dated November 14, 1988, for an Order or Orders fixing new rates, charges or schedules thereof for electric light, power or energy furnished by TransAlta Utilities Corporation to and for the public in Alberta during the years 1988, 1989, and 1990 Dated December 15, 1989
Decision E95062	TransAlta Utilities Corporation In the matter of an application dated October 14, 1994 by TransAlta Utilities Corporation for Approval of a Load Retention Agreement for Foothills Jenner Gas Compression Facility. Dated May 31, 1995
Decision U97065	Alberta Power Limited (APL), Edmonton Power Inc. (EPI), TransAlta Utilities Corporation (TransAlta or TAU) and the Grid Company of Alberta (Gridco) Requesting the Board to Approve Certain Prices and Tariffs Pursuant to section 75 of the EU Act to be Effective January 1996. For 1996, Gridco was appointed to act as the Transmission Administrator.
Decision U97096	NOVA Gas Transmission Ltd. Application for Approval of a New Service Offering the Load Retention Service (LRS) Including Applicable Terms and Conditions of Service. Dated November 14, 1997
Decision 98-21	Imperial Oil Resources Limited, Application to Construct and Operate the Thicksilver Pipeline Project
Decision U99102	Canadian Utilities Limited, Northwestern Utilities Limited, and Canadian Western Natural Gas Company Limited Application for Renewal of the Reorganization of NUL and CWNG Dated November 1, 1999
Decision 2000-9	ATCO Gas and Pipelines Ltd. (CWNG) 1997 Return on Common Equity and Capital Structure; 1998 GRA Phase I Dated March 2, 2000

Decision 2000-82	ATCO Gas and Pipelines Ltd. (CWNG) Request to withdraw the 1999 GRA and assessment of the need for a 2000 GRA Dated December 22, 2000
Decision 2000-85	Northwestern Utilities Limited Approval of Rates, Tolls, Charges, and Terms and Conditions of Service for Core Customers, and Approval of Amendments to the North Core Agreement Dated December 22, 2000
Decision 2001-84	TransAlta Utilities Corporation Industrial Power Consumers and Cogenerators Association of Alberta Review and Variance of Decisions U99099 and 2000-3 Dated November 27, 2001
Decision 2001-96	ATCO Gas South 2001/2002 General Rate Application, Phase I Dated December 12, 2001
Decision 2001-97	ATCO Pipelines South 2001-2002 General Rate Application Phases I and II Dated December 12, 2001
Decision 2001-105	ATCO Electric Ltd. ATCO Gas and Pipelines Ltd., and Northwestern Utilities Limited (ATCO Companies) Pension Filing – Negotiated Settlement Dated December 31, 2001
Decision 2001-110	Methodology for Managing Gas Supply Portfolios Determining Gas Cost Recovery Rates Proceeding and Gas Rate Unbundling Proceeding Part B-1: Deferred Gas Account Reconciliation for ATCO Gas Dated December 12, 2001
Decision 2002-116	ATCO Gas and Pipelines Ltd. (North) Application to Approve 2002 Rates, Amended North Core Agreement and Sale of Beaverhill Lake and Fort Saskatchewan Properties Dated December 24, 2002
Decision 2002-058	Nova Gas Transmission Ltd. Application to Construct Fort Saskatchewan Extension and Scotford, Josephburg and Astotin Sales Meter Stations Dated July 2, 2002

Decision 2002-069	ATCO Group Affiliate Transactions and Code of Conduct Proceeding, Part A: Asset Transfer, Outsourcing Arrangements and GRA Issues Dated July 26, 2002
Decision 2002-097	ATCO Gas South 2001/2002 General Rate Application, Carbon Storage Transfer and Part A: Asset Transfer, Outsourcing Arrangements, and GRA Issues – Compliance Filing Dated November 19, 2002
Decision 2003-035	ATCO Pipelines North and South 2003/2004 General Rate Application Phase I – Request for Approval to Commence a Negotiated Settlement Dated April 30, 2003
Decision 2003-040	ATCO Group Affiliate Transactions and Code of Conduct Proceeding, Part B: Code of Conduct Dated May 22, 2003
Decision 2003-042	ATCO Pipelines North Application for Approval of UFG Methodology
Decision 2003-051	NOVA Gas Transmission Ltd. 2003 Revenue Requirement and Tariff Settlement Applications Dated June 24, 2003
Decision 2003-061	AltaLink Management Ltd. and TransAlta Utilities Corporation Transmission Tariffs Dated August 3, 2003
Decision 2003-071	ATCO Electric Ltd. 2003-2004 General Tariff Application Rate Case Deferrals Application 2001 Deferral Application Dated October 2, 2003
Decision 2003-072	ATCO Gas 2003/2004 General Rate Application Phase I Dated October 1, 2003
Decision 2003-073	ATCO Electric, ATCO Gas, ATCO Pipelines (the ATCO Utilities) ATCO I-Tek Information Technology Master Services Agreement (MSA Module) Dated September 26, 2003

Order U99042	NOVA Gas Transmission Ltd. Load Retention Service 2 Dated April 29, 1999
Order U99130	Canadian Western Natural Gas and Northwestern Utilities Applied to the Board Requesting Approval to Amend the Approved Transactions in Include the Transfer of the Producing and Gathering Assets of Northwestern (the P&G Assets) to Canadian Western. Dated December 21, 1999